Frost Brown Todd LLC
ATTORNEYS

Mark David Goss
Member
859.244.3232
mgoss@fbtlaw.com

May 10, 2011

RECEIVED
MAY 10 2011
PUBLIC SERVICE COMMISSION

VIA HAND-DELIVERY

Mr. Jeffrey Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602-0615

Re: In the Matter of: The Joint Application of Duke Energy Corporation, Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisition Corporation, and Progress Energy, Inc., for Approval of the Indirect Transfer of Control of Duke Energy Kentucky, Inc. PSC Case No. 2011-00124

Dear Mr. Derouen:

Please find enclosed for filing with the Commission in the above-referenced case an original and ten (10) copies of the Responses of Duke Energy Corporation, Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisition Corporation, and Progress Energy, Inc. ("Joint Applicants"), to the Commission Staff's Initial Information Request and the Kentucky Attorney General's Initial Data Request.

In addition, you will also find enclosed for filing and consideration by the Commission Joint Applicants' Petition for Confidential Treatment of Information made pursuant to 807 KAR 5:001, Section 7. Please note that one copy of the designated confidential portions of Joint Applicants' Responses to the Commission Staff's Initial Information Request is enclosed in a sealed envelope. However, because of the voluminous nature of the confidential portions of Joint Applicants' Responses to the Attorney General's Initial Data Request, one copy of those documents is being placed in boxes clearly marked "CONFIDENTIAL".

Due to their very sensitive, confidential and proprietary nature, the Joint Applicants' Petition seeks confidential treatment for the <u>entire</u> documents for all the reasons set forth in the Petition for Confidential Treatment.

Please also be advised that the Joint Applicants are this date hand-delivering copies of this information to the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention.

Please file these documents in the record and return file-stamped copies to me.

Please do not hesitate to contact me if you have any questions.

Sincerely yours,

Mark David Goss

Enclosures

cc: Dennis G. Howard, II
Lawrence W. Cook (via hand-delivery)

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 10 2011

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE JOINT APPLICATION OF DUKE ENERGY CORPORATION, CINERGY CORP., DUKE ENERGY OHIO, INC., DUKE ENERGY KENTUCKY, INC., DIAMOND ACQUISITION CORPORATION, AND PROGRESS ENERGY, INC., FOR APPROVAL OF THE INDIRECT TRANSFER OF CONTROL OF DUKE ENERGY KENTUCKY, INC.	)	**CASE NO. 2011-00124**

JOINT APPLICANTS' RESPONSE TO THE COMMISSION STAFF'S INITIAL INFORMATION REQUESTS

Comes now Duke Energy Corporation ("Duke Energy"), Cinergy Corp. ("Cinergy"), Duke Energy Ohio, Inc. ("Duke Energy Ohio"), Duke Energy Kentucky, Inc. ("Duke Energy Kentucky"), Diamond Acquisition Corporation ("Diamond"), and Progress Energy, Inc. ("Progress Energy") (collectively, "Joint Applicants"), and tender their response to the Commission Staff's Initial Information Requests, respectfully stating as follows:

1. The Joint Applicants' response consists of one original and ten copies of nine volumes of non-confidential information and one sealed envelope containing confidential information.

2. In accordance with the Commission's April 28, 2011 requests for information and the requirements of 807 KAR 5:001, the verifications for the Joint Applicants' responses are attached hereto.[1] The persons responsible for providing the Joint Applicants' Responses are:

[1] As of the date of filing, only a photocopy of the verifications for Mr. Batson, Mr. Henderschott, Mr. Stanley and Mr. Young were available. The originals will be filed once they are received.

Richard Bates	Christopher Fallon	James E. Rogers
Elliott Batson	John Finnigan	Brian Savoy
Keith Butler	Mike Hendershott	Jim Stanley
Carl Council	Julie Janson	William Don Wathen
Andrew Cox	William Johnson	Jennifer Weber
Swati Daji	Jose Merino	Holly Wenger
Stephen DeMay	A. R. Mullinax	Danny Wiles
Tim Duff	Barry Pulskamp	Steve Young

3. The volumes containing confidential information are labeled "confidential." A petition for confidential treatment of information is attached hereto and incorporated herein by reference.

This 10th day of May, 2011.

Respectfully submitted,

Mark David Goss
David S. Samford
Frost Brown Todd LLC
250 West Main Street, Suite 2800
Lexington, KY 40507-1749
(859) 231-0000 – Telephone
(859) 231-0011 – Facsimile

Counsel for Joint Applicants,
Duke Energy Corporation
Cinergy Corporation
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
Diamond Acquisition Corporation and
Progress Energy, Inc.

- and -

Rocco D'Ascenzo
Amy B. Spiller
Duke Energy Business Services LLC
139 East Fourth Street
1301 Main
P. O. Box 960
Cincinnati, Ohio 45201-0960

Counsel for Joint Applicants,
Duke Energy Corporation
Cinergy Corporation
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc. and
Diamond Acquisition Corporation

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing has been served via hand delivery to the following party on this 10th day of May 2011:

Hon. Dennis Howard
Hon. Larry Cook
Office of the Attorney General
Utility Intervention and Rate Division
1024 Capital Center Drive
Frankfort, Kentucky 40601

Counsel for Joint Applicants,
Duke Energy Corporation
Cinergy Corporation
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
Diamond Acquisition Corporation and
Progress Energy, Inc.

LEXLibrary 0106219.0583960 457117v1

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Richard B. Bates, being duly sworn, deposes and says that he is the Vice President - Mergers & Acquisitions, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Richard B. Bates, Affiant

Subscribed and sworn to before me by Richard B. Bates on this 5th day of May 2011.

Nancy H. Taylor
NOTARY PUBLIC

My Commission Expires: 01/26/2012

413108

VERIFICATION

State of North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Elliott Batson, Jr., being duly sworn, deposes and says that he is the Vice President, Regulated Fuels, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Elliott Batson, Jr.

Elliott Batson, Jr., Affiant

Subscribed and sworn to before me by Elliott Batson on this 5 day of May 2011.

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

Rita G Kale

NOTARY PUBLIC

My Commission Expires: 6/17/12

412613

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Keith Butler, being duly sworn, deposes and says that he is the Senior Vice President, Tax, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Keith Butler, Affiant

Subscribed and sworn to before me by Keith G. Butler on this 2nd day of May 2011.

Judith A. Reese
NOTARY PUBLIC

My Commission Expires: 02/26/2012

412588

VERIFICATION

State of North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Carl J. Council, Jr., being duly sworn, deposes and says that he is the Director Asset Accounting, Duke Energy Business Services, LLC, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Carl J. Council, Jr., Affiant

Subscribed and sworn to before me by Carl J. Council, Jr. on this 9 day of May 2011.

Patricia C. Ross
NOTARY PUBLIC

My Commission Expires: 10-17-2014

PATRICIA C. ROSS
NOTARY PUBLIC
MECKLENBURG CO., NC

412770

VERIFICATION

State of North Carolina)
) **SS:**
County of Wake)

The undersigned, Andrew D. Cox, being duly sworn, deposes and says that he is employed by Progress Energy, Inc., as Director, CBE Program Office and Integration Planning; that on behalf of Progress Energy, Inc., he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Andrew D. Cox, Affiant

Subscribed and sworn to before me by Andrew D. Cox on this ____ day of May 2011.

DENISE P DEVIVERO
NOTARY PUBLIC
WAKE COUNTY, NC

Denise P. deViuero
NOTARY PUBLIC

My Commission Expires: July 30, 2015

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Swati V. Daji, being duly sworn, deposes and says that she is the Vice President, Global Risk Management & Insurance & CRO, that she has supervised the preparation of the responses to the foregoing information request; and that the matters set forth in the foregoing response to information request are true and accurate to the best of her knowledge, information and belief, after reasonable inquiry.

Swati V. Daji
Swati V. Daji, Affiant

Subscribed and sworn to before me by Swati V. Daji on this 9 day of May 2011.

Patricia C. Ross
NOTARY PUBLIC

My Commission Expires: 10-17-2014

PATRICIA C. ROSS
NOTARY
PUBLIC
MECKLENBURG CO., NC

413829

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Stephen G. De May, being duly sworn, deposes and says that he is the Senior Vice President, Investor Relations & Treasurer, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Stephen G. De May
Stephen G. De May, Affiant

Subscribed and sworn to before me by Stephen G. DeMay on this 4 day of May 2011.

[signature]
NOTARY PUBLIC

My Commission Expires: 10.22.2011

412493

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Tim Duff, being duly sworn, deposes and says that he is the General Manager, Retail Customer & Regulated Strategy, Duke Energy Business Services LLC, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Tim Duff, Affiant

Subscribed and sworn to before me by Tim Duff on this 3 day of May 2011.

NOTARY PUBLIC
CHRISTOPHER LEE HAMRICK

My Commission Expires:

My Commission Expires October 24, 2014

412849

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Christopher M. Fallon, being duly sworn, deposes and says that he is the Vice President, Office of Nuclear Development, that he has supervised the preparation of the response to the foregoing information request; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Christopher M. Fallon

Christopher M. Fallon, Affiant

Subscribed and sworn to before me by Christopher M. Fallon on this 9 day of May 2011.

FREDA K CRUMP NOTARY PUBLIC LINCOLN COUNTY, NC

Freda K. Crump

NOTARY PUBLIC

My Commission Expires: August 17, 2011

413991

VERIFICATION

State of Ohio)
) **SS:**
County of Hamilton)

The undersigned, John Finnigan, being duly sworn, deposes and says that he is the Vice President, Government & Regulatory Affairs, that he has supervised the preparation of the response to Attorney General-Data Request-01-106; and that the matters set forth in the foregoing response to said request are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

John Finnigan

John Finnigan, Affiant

Subscribed and sworn to before me by John FINNIGAN on this 5th day of May 2011.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2014

413348

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Michael S. Hendershott, being duly sworn, deposes and says that he is the Director, Service Financial Accounting & Reporting, Duke Energy Business Services LL, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Michael S. Hendershott, Affiant

Subscribed and sworn to before me by May on this 6 day of May 2011.

NOTARY PUBLIC

My Commission Expires:
11-29-2015

412848

VERIFICATION

State of Ohio	)	
	)	**SS:**
County of Hamilton	)	

The undersigned, Julia S. Janson, being duly sworn, deposes and says that she is the President, Duke Energy Ohio and Duke Energy Kentucky, that she has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of her knowledge, information and belief, after reasonable inquiry.

Julia S. Janson

Julia S. Janson, Affiant

Subscribed and sworn to before me by Julia S. Janson on this 9 day of May 2011.

Amy B. Spiller

NOTARY PUBLIC

My Commission Expires:

AMY BETH SPILLER, Attorney at Law
Notary Public, State of Ohio
My Commission Has No Expiration Date
Section 147.03

VERIFICATION

State of North Carolina)
) **SS:**
County of Wake)

The undersigned, William D. Johnson, being duly sworn, deposes and says that he is employed by Progress Energy, Inc., as Chairman, President and Chief Executive Officer; that on behalf of Progress Energy, Inc., he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

William D. Johnson
William D. Johnson, Affiant

Subscribed and sworn to before me by William D. Johnson on this 6 day of May 2011.

Nancy B. Little
NOTARY PUBLIC

My Commission Expires: July 1, 2015

412410

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenberg)

The undersigned, Jose Merino, being duly sworn, deposes and says that he is the Director, Load Forecasting, that he has supervised the preparation of the response to the foregoing information request; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Jose Merino, Affiant

Subscribed and sworn to before me by Jose Merino on this 9th day of May 2011.

Nancy H. Taylor
NOTARY PUBLIC

My Commission Expires: January 26, 2012

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, AR Mullinax, being duly sworn, deposes and says that he is the Senior Vice President & Chief Information Officer, Duke Energy Business Services, LLC, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

AR Mullinax

AR Mullinax, Affiant

Subscribed and sworn to before me by AR Mullinax on this 2nd day of May 2011.

Deborah K. Bolan

NOTARY PUBLIC

My Commission Expires: 10-29-12

412608

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Barry E. Pulskamp, being duly sworn, deposes and says that he is the Senior Vice President, Regulated Fleet Operations, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

BE Pulskamp

Barry E. Pulskamp, Affiant

Subscribed and sworn to before me by Barry E. Pulskamp on this 5th day of May 2011.

Lisa Miner Rosner

NOTARY PUBLIC

My Commission Expires: State of Ohio Hamilton County

LISA MINER ROSNER, Attorney at Law
NOTARY PUBLIC - STATE OF OHIO
My Commission has no expiration date. Section 147.03 O.R.C.

412615

VERIFICATION

State of North Carolina	)	
	)	**SS:**
County of Mecklenburg	)	

The undersigned, James E. Rogers, Jr., being duly sworn, deposes and says that he is the Chairman, President and Chief Executive Officer of Duke Energy Corporation that he has ~~personal knowledge of the matters set forth in the foregoing testimony, and that the answers~~ contained therein are true and correct to the best of his information, knowledge and belief.

James E. Rogers, Jr., Affiant

Subscribed and sworn to before me by James E. Rogers on this 3rd day of ~~April~~ may 2011.

Deborah K. Bolan

NOTARY PUBLIC

DEBORAH K. BOLAN
NOTARY
PUBLIC
MECKLENBURG COUNTY, NC

My Commission Expires: 10-29-12

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Brian D. Savoy, being duly sworn, deposes and says that he is the Managing Director Corporate Financial Planning Analysis, Duke Energy Business Services, LLC, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Brian D. Savoy, Affiant

Subscribed and sworn to before me by Amy Livezey on this 2nd day of May 2011.

NOTARY PUBLIC

My Commission Expires: 11/16/2012

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Jim Stanley, being duly sworn, deposes and says that he is the Senior Vice President of Power Delivery, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Jim Stanley, Affiant

Subscribed and sworn to before me by Jim Stanley on this 9th day of May 2011.

Diane M. Wilkinson
NOTARY PUBLIC

My Commission Expires:

DIANE M. WILKINSON
Notary Public
North Carolina
Lincoln County

412548

VERIFICATION

State of Ohio	)	
	)	SS:
County of Hamilton	)	

The undersigned, William Don Wathen Jr., being duly sworn, deposes and says that he is the General Manager and Vice President of Rates of Duke Energy Ohio and Duke Energy Kentucky, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information, and belief, after reasonable inquiry.

William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen JR on this 9th day of May 2011.

NOTARY PUBLIC

My Commission Expires:

NOTARIAL SEAL
STATE OF OHIO

ROCCO O. D'ASCENZO
ATTORNEY AT LAW
Notary Public, State of Ohio
My Commission Has No Expiration
Section 147.03 R.C.

412439

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Jennifer Weber, being duly sworn, deposes and says that she is the Group Executive, Human Resources & Corporate Relations, Duke Energy Business Services, LLC, that she has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of her knowledge, information and belief, after reasonable inquiry.

Jennifer Weber
Jennifer Weber, Affiant

Subscribed and sworn to before me by Jennifer Weber on this 3 day of May 2011.

Deborah S. Rome Deborah S. Rome
NOTARY PUBLIC

My Commission Expires: January 24, 2015

412611

VERIFICATION

State of North Carolina)
)   **SS:**
County of Wake)

The undersigned, Holly H. Wenger, being duly sworn, deposes and says that she is employed by Progress Energy, Inc., as Assistant Secretary; that on behalf of Progress Energy, Inc., she has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of her knowledge, information and belief, after reasonable inquiry.

Holly H Wenger
Holly H. Wenger, Affiant

Subscribed and sworn to before me by Holly H. Wenger on this ____ day of May 2011.

Pamela P. Hensley
NOTARY PUBLIC

PAMELA P. HENSLEY
NOTARY PUBLIC
Johnston County
North Carolina
My Commission Expires 12/11/11

My Commission Expires: 12/11/11

412410

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Danny Wiles, being duly sworn, deposes and says that he is the General Manager of Duke Energy & Vice President US Franchised Electric & Gas Accounting, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Danny Wiles

Danny Wiles, Affiant

Subscribed and sworn to before me by Danny Wiles on this 2 day of May 2011.

Kim V. Beal

NOTARY PUBLIC

My Commission Expires: October 24, 2014

412528

VERIFICATION

State of North Carolina)
) **SS:**
County of Mecklenburg)

The undersigned, Steve K. Young, being duly sworn, deposes and says that he is the Senior Vice President, that he has supervised the preparation of the responses to the foregoing information requests; and that the matters set forth in the foregoing responses to information requests are true and accurate to the best of his knowledge, information and belief, after reasonable inquiry.

Steven K Young
Steve K. Young, Affiant

Subscribed and sworn to before me by Steve K. Young on this 9 day of May 2011.

Patricia C. Ross
NOTARY PUBLIC

My Commission Expires: 10-17-2014

PATRICIA C. ROSS
NOTARY PUBLIC
MECKLENBURG CO., NC

413832

COMMONWEALTH OF KENTUCKY

BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED

MAY 10 2011

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF:

THE JOINT APPLICATION OF DUKE ENERGY CORPORATION, CINERGY CORP., DUKE ENERGY OHIO, INC., DUKE ENERGY KENTUCKY, INC., DIAMOND ACQUISITION CORPORATION, AND PROGRESS ENERGY, INC FOR APPROVAL OF THE INDIRECT TRANSFER OF CONTROL OF DUKE ENERGY KENTUCKY	)	Case No. 2011-0124

JOINT APPLICANTS' PETITION
FOR CONFIDENTIAL TREATMENT OF INFORMATION

Duke Energy Corporation (Duke Energy), Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisition Corporation, and Progress Energy, Inc., (collectively Joint Applicants), pursuant to 807 KAR 5:001, Section 7, respectfully request the Commission to grant confidentiality to, and protect from public disclosure, certain information provided by Joint Applicants in response to the Commission Staff's first set of discovery requests and the Attorney General's first set of information requests in this proceeding. In support, the Joint Applicants, individually and collectively, state:

1. Joint Applicants are filing responses to the initial information requests of the Commission Staff and the Attorney General on May 10, 2011. These responses contain the following Confidential Information:

(a) Attorney General Request 12 - analysis and analyst presentations of the debt associated with North Carolina Lee Nuclear Station;

(b) Attorney General Request 28 - Duke Energy Kentucky's most recent load forecast;

(c) Attorney General Request 41 - board of director and meeting minutes;[1]

(d) Attorney General Request 48 - reports/ analysis of economies of scale and scope;[2]

(e) Attorney General Request 52 - costs to achieve discussion;

(f) Attorney General Request 54 - internal allocations calculations;

(g) Attorney General Request 55 - internal allocations calculations regulated and nonregulated companies;

(h) Attorney General Request 57 - due diligence reports;[3]

(i) Attorney General Request 64 - presentations and financial analysis;

(j) Attorney General Request 67 - Hart-Scott-Rodino filing;

(k) Staff Request 32- merger-related reports/analysis;

2. The Kentucky Open Records Act exempts from disclosure certain information, *inter alia* proprietary information and/or sensitive commercial information. KRS 61.878(1)(c). The information identified above is confidential or proprietary information and, if openly disclosed, would permit an unfair commercial advantage to competitors of the Joint Applicant(s) that disclosed the records.

3. Attorney General Request Number 12 asks in relevant part for information relating to Duke Energy's construction of its Lee Nuclear Station. This confidential

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[1] The requested documents were also responsive to AG-DR-01-067. Rather than providing multiple copies of documents, Joint Applicants have provided its responses as part of AG-DR-01-067.

[2] *Id.*

[3] *Id.*

information was created for Duke Energy as part of its ongoing analysis of the project and is neither jurisdictional to Kentucky nor does it involve Duke Energy Kentucky. The documents responsive to the request include internal documents that analyze the project, including timing of construction, assumptions regarding financing, and confidential presentations. Release of this proprietary and confidential information will harm Duke Energy and its customers in the Carolinas because it will give insight into Duke Energy's proprietary and confidential analysis of the project and assumptions in obtaining financing and put the company at a competitive disadvantage in the marketplace in negotiating contracts with outside vendors.

4. Attorney General Request Number 28 includes Duke Energy Kentucky's most recent draft of its future load forecast. This confidential forecast shows Duke Energy Kentucky's expected sales by customer class for the next twenty-five years. This information is highly sensitive and proprietary in that it is forward looking and shows Duke Energy Kentucky's own analysis and projections of its future sales and power needs. Duke Energy Kentucky would be at a competitive disadvantage in the marketplace for services or replacement power if it was required to disclose the Company's needs as part of this proceeding.

5. Attorney General Requests Numbers 41, 48, 52, 55, 57, 64 and Staff Request Number 32 seek meeting minutes, reports and analysis related to economies of scale and scope, analysis of costs to achieve, due diligence reports, and financial presentations and other reports/analysis, respectively, related to the negotiation and implementation of this merger transaction. Release of this information will harm the Joint Applicants. This information is highly confidential and proprietary in that it discusses the business analysis

and strategy of Duke Energy and Progress Energy related to considering, negotiating and entering into the transaction. Release of this information will place the Joint Applicants at competitive disadvantages in all jurisdictions as it will provide insight into the Joint Applicants' sensitive and confidential business strategies and hinder the Joint Applicants' efforts to obtain the desired synergies associated with the transaction. Additionally, a significant portion of this information was submitted as part of the Joint Applicants' Hart-Scott-Rodino filing pursuant to 15 U.S.C. Section 18a, which is considered confidential and exempt from disclosure under the Freedom of Information Act, and is thus exempt from disclosure under the Kentucky Open Records Act pursuant to KRS 61.878(1)(k).

6. Attorney General Requests Numbers 52 and 54 includes Duke Energy's initial draft analysis regarding allocation of costs for the combined company after completion of the merger. This information is highly confidential and proprietary in that it is both preliminary in nature and describes Duke Energy's business strategy regarding cost management within the company following the implementation of the merger.

7. Attorney General Request Number 67 seeks the Joint Applicants' Hart-Scott-Rodino filing. As noted above, the Hart-Scott-Rodino filing contains confidential and proprietary commercial information related directly to issues of competition, and public disclosure of these materials would cause the Joint Applicants harm. Pursuant to 15 U.S.C. Section 18a (h), the entirety of a Hart-Scott Rodino filing is considered confidential, and is exempt from disclosure under the federal Freedom of Information Act. The Hart-Scott Rodino filing is also exempt from disclosure under the Kentucky Open Records Act, pursuant to KRS 61.878(1)(k), as a result. Furthermore, Joint

Applicants are providing the non-privileged portions of this filing under seal.[4] This information has routinely been afforded confidential treatment by this Commission given its sensitive nature and protection under federal procedures,[5] and such treatment should be provided again.

8. Disclosure of the individual factors contained in the aforementioned data requests would damage Joint Applicants' positions and business interests. This information reveals the business models the Joint Applicants used, the procedures followed and the factors/inputs considered - in entering into this transaction. If the Commission grants public access to the information requested, competitors and possible vendors and service providers could manipulate pricing for services to the detriment of Joint Applicants and their respective ratepayers.

9. The information for which Joint Applicants seek confidential treatment has not been publicly disclosed and is only known and available to those individuals employed by the Joint Applicants' respective companies who have a legitimate business reason to have access to the information.

10. Joint Applicants do not object to limited disclosure of the non-privileged confidential information described herein, pursuant to an acceptable protective agreement, to the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

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[4] Information that is privileged and thus protected under the doctrines of attorney client privilege and attorney work product has been withheld. Documents that are only partially privileged are provided in redacted form.

[5] *See e.g. In Re. Joint Application of PPL Corporation et al., for Approval of an Acquisition of Ownership and Control Over Utilities,* Case No. 2010-204, (Letter Granting Confidential Protection)(September 30, 2010).

11. In accordance with the provisions of 807 KAR 5:001 Section 7, the Joint Applicants are filing one set of the Confidential Information under seal, in unredacted format, except for redacting privileged and confidential attorney-client communications. Joint Applicants agree to make the Confidential Information available to the Attorney General's office and any other non-competitive intervenor in this case upon the execution of an appropriate confidentiality agreement by such party or parties.

WHEREFORE, Joint Applicants respectfully request that the Commission grant confidentiality to, and protect from public disclosure, certain information filed herewith under seal as set forth herein.

This 10th day of May, 2011.

Respectfully submitted,

Mark David Goss
David S. Samford
Frost Brown Todd LLC
250 West Main Street, Suite 2800
Lexington, KY 40507-1749
(859) 231-0000 – Telephone
(859) 231-0011 – Facsimile

Counsel for Joint Applicants,
Duke Energy Corporation
Cinergy Corporation
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
Diamond Acquisition Corporation and
Progress Energy, Inc.

- and -

Rocco D'Ascenzo
Amy B. Spiller
Duke Energy Business Services LLC
139 East Fourth Street
1301 Main
P. O. Box 960
Cincinnati, Ohio 45201-0960

Counsel for Joint Applicants,
Duke Energy Corporation
Cinergy Corporation
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc. and
Diamond Acquisition Corporation

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing has been served via hand delivery to the following party on this 10th day of May 2011:

Hon. Dennis Howard
Hon. Larry Cook
Office of the Attorney General
Utility Intervention and Rate Division
1024 Capital Center Drive
Frankfort, Kentucky 40601

Counsel for Joint Applicants,
Duke Energy Corporation
Cinergy Corporation
Duke Energy Ohio, Inc.
Duke Energy Kentucky, Inc.
Diamond Acquisition Corporation and
Progress Energy, Inc.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE JOINT APPLICATION OF DUKE ENERGY CORPORATION, CINERGY CORP., DUKE ENERGY OHIO, INC., DUKE ENERGY KENTUCKY, INC., DIAMOND ACQUISITION CORPORATION, AND PROGRESS ENERGY, INC., FOR APPROVAL OF THE INDIRECT TRANSFER OF CONTROL OF DUKE ENERGY KENTUCKY, INC.	)	CASE NO. 2011-00124

INDEX TO THE JOINT APPLICANTS' RESPONSE TO THE COMMISSION STAFF'S INITIAL INFORMATION REQUESTS

Volumes Containing Non-Confidential Information

Volume I	Tabs 1-7 and 8A-8D
Volume II	Tabs 8E-8F
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Confidential Information

Sealed Envelope	Tab 32

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-001

REQUEST:

Provide corporate organizational charts, showing all subsidiary and affiliated companies of Duke Energy and Progress as of December 31, 2010. The format should be similar to that used in each company's Securities and Exchange Commission ("SEC") reports. In addition, indicate whether the subsidiary or affiliated company is an active or inactive entity.

RESPONSE:

Please see Attachment Staff-DR-01-001(Duke)

The following have been dissolved:

Duke Energy International Bolivia Holdings No. 1, LLC (Delaware);
TE Happy Jack, LLC (Delaware);
Cinergy Retail Power, L.P. (Delaware).

Please see Attachment Staff DR-01-001(Progress)

PERSON RESPONSIBLE: James E. Rogers
Holly H. Wenger (Progress)

Exhibit No. 21

PROGRESS ENERGY, INC.
List of Subsidiaries

The following is a list of certain direct and indirect subsidiaries of Progress Energy, Inc., and their respective states of incorporation as of December 31, 2010. All other subsidiaries, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	North Carolina
Florida Progress Corporation	Florida
Florida Power Corporation d/b/a/ Progress Energy Florida, Inc.	Florida

EX-21 7 dex21.htm LIST OF SUBSIDIARIES

EXHIBIT 21

LIST OF SUBSIDIARIES

The following is a list of certain subsidiaries (greater than 50% owned) of the registrant and their respective states or countries of incorporation:

Actividades A y D, S.A (Guatemala).
Advance SC LLC (South Carolina)
Aguaytia Energy del Peru S.R.L. Ltda. (Peru)
Aguaytia Energy, LLC (Delaware)
Attiki Denmark ApS (Denmark)
Bison Insurance Company Limited (Bermuda)
Brownsville Power I, L.L.C. (Delaware)
Caldwell Power Company (North Carolina)
Catamount Celtic Energy Limited (Scotland)
Catamount Energy Corporation (Vermont)
Catamount Energy SC 1 (Scotland)
Catamount Energy SC 2 (Scotland)
Catamount Energy SC 3 (Scotland)
Catamount Rumford Corporation (Vermont)
Catamount Sweetwater 1 LLC (Vermont)
Catamount Sweetwater 2 LLC (Vermont)
Catamount Sweetwater 3 LLC (Vermont)
Catamount Sweetwater 4-5 LLC (Vermont)
Catamount Sweetwater 6 LLC (Vermont)
Catamount Sweetwater Corporation (Vermont)
Catamount Sweetwater Holdings LLC (Vermont)
Catawba Manufacturing and Electric Power Company (North Carolina)
CEC UK1 Holding Corp. (Vermont)
CEC UK2 Holding Corp. (Vermont)
CEC Wind Development LLC (Vermont)
Centra Gas Toluca S.R.L. de C.V. (Mexico)
CGP Global Greece Holdings, SA (Greece)
Cinergy Climate Change Investments, LLC (Delaware)
Cinergy Corp. (Delaware)
Cinergy Foundation, Inc. (Indiana)
Cinergy General Holdings, LLC (Delaware)
Cinergy Global (Cayman) Holdings, Inc. (Cayman Islands)
Cinergy Global Ely, Inc. (Delaware)
Cinergy Global Hellas S.A. (Greece)
Cinergy Global Holdings, Inc. (Delaware)
Cinergy Global Power (UK) Limited (England)
Cinergy Global Power Africa (Proprietary) Limited (South Africa)
Cinergy Global Power, Inc. (Delaware)
Cinergy Global Resources, Inc. (Delaware)
Cinergy Global Trading Limited (England)
Cinergy Global Tsavo Power (Cayman Islands)
Cinergy Investments, Inc. (Delaware)
Cinergy Limited Holdings, LLC (Delaware)
Cinergy Origination & Trade, LLC (Delaware)
Cinergy Power Generation Services, LLC (Delaware)
Cinergy Receivables Company LLC (Delaware)
Cinergy Retail Power General, Inc. (Texas)
Cinergy Retail Power Limited, Inc. (Delaware)
Cinergy Retail Power, L.P. (Delaware)
CST General, LLC (Texas)
CST Green Power, L.P. (Delaware)
CST Limited, LLC (Delaware)
D/FD Holdings, LLC (Delaware)
D/FD International Services Brasil Ltda. (Brazil)
D/FD Operating Services LLC (Delaware)
DE Marketing Canada Ltd. (Canada-Federal)
DE Nuclear Engineering, Inc. (North Carolina)
DEB - Pequenas Centrais Hidrelétricas Ltda. (Brazil)
DEGS Biomass, LLC (Delaware)
DEGS NC Solar, LLC (Delaware)
DEGS O&M, LLC (Delaware)
DEGS of Boca Raton, LLC (Delaware)
DEGS of Cincinnati, LLC (Ohio)
DEGS of Delta Township, LLC (Delaware)
DEGS of Lansing, LLC (Delaware)
DEGS of Monaca, LLC (Delaware)
DEGS of Narrows, LLC (Delaware)
DEGS of Philadelphia, LLC (Delaware)
DEGS of San Diego, Inc. (Delaware)
DEGS of Shreveport, LLC (Delaware)
DEGS of South Charleston, LLC (Delaware)
DEGS of St. Bernard, LLC (Delaware)
DEGS of St. Paul, LLC (Delaware)
DEGS of Tuscola, Inc. (Delaware)
DEGS Solar, LLC (Delaware)
DEGS Wind I, LLC (Delaware)
DEGS Wind Supply II, LLC (Delaware)
DEGS Wind Supply, LLC (Delaware)
Delta Township Utilities, LLC (Delaware)
DENA Partners Holding, LLC (Delaware)
DETMI Management, Inc. (Colorado)
Dixilyn-Field (Nigeria) Limited (Nigeria)
Dixilyn-Field Drilling Company (Delaware)
Dixilyn-Field International Drilling Company, S.A. (Panama)
DTMSI Management Ltd (Canada)
Duke Broadband, LLC (Delaware)
Duke Capital Partners, LLC (Delaware)
Duke Communications Holdings, Inc. (Delaware)
Duke Energy Americas, LLC (Delaware)
Duke Energy Business Services LLC (Delaware)
Duke Energy Carolinas Plant Operations, LLC (Delaware)
Duke Energy Carolinas, LLC (North Carolina)
Duke Energy Cerros Colorados, S.A. (Argentina)
Duke Energy Commercial Enterprises, Inc. (Indiana)
Duke Energy Corporate Services, Inc. (Delaware)
Duke Energy Development Pty Ltd (Australia)
Duke Energy Egenor S. en C. por A. (Peru)
Duke Energy Electroquil Partners (Delaware)
Duke Energy Engineering, Inc. (Ohio)
Duke Energy Fayette II, LLC (Delaware)
Duke Energy Fossil-Hydro California, Inc. (Delaware)
Duke Energy Fossil-Hydro, LLC (Delaware)
Duke Energy Generating S.A. (Argentina)
Duke Energy Generation Services Holding Company, Inc. (Delaware)
Duke Energy Generation Services, Inc. (Delaware)

Cinergy Solutions - Utility, Inc. (Delaware)
Cinergy Solutions Partners, LLC (Delaware)
Cinergy Technology, Inc. (Indiana)
Cinergy UK, Inc. (Delaware)
Cinergy Wholesale Energy, Inc. (Ohio)
Cinergy-Centrus Communications, Inc (Delaware)
Cinergy-Centrus, Inc. (Delaware)
CinFuel Resources, Inc. (Delaware)
CinPower I, LLC (Delaware)
Claiborne Energy Services, Inc. (Louisiana)
Comercializadora Duke Energy de Centro America, Limitada (Guatemala)
CSCC Holdings Limited Partnership (British Columbia, Canada)
CSGP General, LLC (Texas)
CSGP Limited, LLC (Delaware)
Duke Energy Group Holdings, LLC (Delaware)
Duke Energy Group, LLC (Delaware)
Duke Energy Hanging Rock II, LLC (Delaware)
Duke Energy Indiana, Inc (Indiana)
Duke Energy Industrial Sales, LLC (Delaware)
Duke Energy International (Europe) Holdings ApS (Denmark)
Duke Energy International (Europe) Limited (United Kingdom)
Duke Energy International Argentina Holdings (Cayman Islands)
Duke Energy International Argentina Marketing/Trading (Bermuda) Ltd. (Bermuda)
Duke Energy International Asia Pacific Ltd. (Bermuda)
Duke Energy International Bolivia Holdings No. 1, LLC (Delaware)
Duke Energy International Brasil Commercial, Ltda. (Brazil)
Duke Energy International Brasil Holdings, LLC (Delaware)
Duke Energy International Brazil Holdings Ltd. (Bermuda)
Duke Energy International Chile C.P.A. (Chile)
Duke Energy International Chile Holding I B.V. (Netherlands)

Duke Energy International Chile Holding II B.V. (Netherlands)
Duke Energy International Comercializadora de El Salvador, S.A. de C.V. (El Salvador)
Duke Energy International del Ecuador Cia. Ltda. (Ecuador)
Duke Energy International El Salvador Investments No. 1 Ltd (Bermuda)
Duke Energy International El Salvador Investments No. 1 y Cia. S. enC. de C.V. (El Salvador)
Duke Energy International El Salvador, S en C de CV (El Salvador)
Duke Energy International Electroquil Holdings, LLC (Delaware)
Duke Energy International Espana Holdings, S.L.U. (Spain)
Duke Energy International Group Cooperatie U.A. (Netherlands)
Duke Energy International Group, Ltd. (Bermuda)
Duke Energy International Guatemala Holdings No. 1, Ltd. (Bermuda)
Duke Energy International Guatemala Holdings No. 2, Ltd. (Bermuda)
Duke Energy International Guatemala Holdings No. 3 (Cayman Islands)
Duke Energy International Guatemala Limitada (Guatemala)
Duke Energy International Guatemala y Compania Sociedad en Comandita por Acciones (Guatemala)
Duke Energy International Holding, Ltd. (Bermuda)
Duke Energy International Holdings B.V. (Netherlands)
Duke Energy International Investments No. 2 Ltd. (Bermuda)
Duke Energy International Latin America, Ltd.(Bermuda)
Duke Energy International Mexico Holding Company I, S. de R.L. de C.V.(Mexico)
Duke Energy International Mexico, S.A. de C.V. (Mexico)
Duke Energy International Netherlands Financial Services B.V. (Netherlands)
Duke Energy International Operaciones Guatemala Limitada (Guatemala)
Duke Energy International Peru Inversiones No. 1, S.R.L. (Peru)
Duke Energy International Peru Investments No. 1, Ltd. (Bermuda)
Duke Energy International PJP Holdings, Ltd.(Bermuda)
Duke Energy International Southern Cone SRL (Argentina)
Duke Energy International Trading and Marketing (UK) Limited (United Kingdom)
Duke Energy International Transmision Guatemala Limitada (Guatemala)
Duke Energy International Uruguay Holdings, LLC (Delaware)
Duke Energy International Uruguay Investments, S.R.L. (Uruguay)
Duke Energy International, Brasil Ltda. (Brazil)
Duke Energy International, Geracao Paranapanema S.A. (Brazil)
Duke Energy International, LLC (Delaware)
Duke Ventures Real Estate, LLC (Delaware)
Duke Ventures, LLC (Nevada)
Duke/Fluor Daniel (North Carolina)
Duke/Fluor Daniel Caribbean, S.E. (Puerto Rico)
Duke/Fluor Daniel El Salvador S.A. de C.V. (El Salvador)
Duke/Fluor Daniel International (Nevada)
Duke/Fluor Daniel International Services (Nevada)
Duke/Fluor Daniel International Services (Trinidad) Ltd. (Trinidad and Tobago)
Duke/Louis Dreyfus L.L.C. (Nevada)
Duke-Cadence, Inc. (Indiana)
Duke-Reliant Resources, Inc. (Delaware)
DukeTec I, LLC
DukeTec II, LLC (Delaware)
DukeTec, LLC (Delaware)
Eastman Whipstock do Brasil Ltda.
Eastman Whipstock, S.A. (Brazil)
Eastover Land Company (Kentucky)
Eastover Mining Company (Kentucky)
Electroquil, S.A. (Ecuador)
Energy Pipelines International Company (Delaware)
Equinox Vermont Corporation (Vermont)
Etenorte S.R.L.(Peru)
Eteselva S. R. L.(Peru)
eVent Resources Holdings LLC (Delaware)
eVent Resources I LLC (Delaware)
eVent Resources Overseas I, LLC (Delaware)
Gas Integral S.R.L. (Peru)
Generadora La Laguna Duke Energy International Guatemala y Cia., S.C.A. (Guatemala)
Green Frontier Windpower Holdings, LLC
Green Frontier Windpower, LLC
Greenville Gas and Electric Light and Power Company (South Carolina)
Happy Jack Windpower, LLC (Delaware)
IGC Aguaytia Partners, LLC (Cayman Islands)
INDU Solar Holdings, LLC
Inver Energy Holdings (Cayman Islands) I
Inver Energy Holdings II (Cayman Islands)
Inver-Energy y Cia. SCA (Cayman Islands)
Kit Carson Windpower, LLC (Delaware)
KO Transmission Company (Kentucky)
Laurel Hill Wind Energy, LLC
LHI, LLC (Delaware)
MCP, LLC (South Carolina)
Miami Power Corporation (Indiana)
Mountain Air Windpower Holdings, LLC (Delaware)
North Allegheny Wind, LLC (Delaware)
NorthSouth Insurance Company Limited (Bermuda)
Notrees Windpower, LP (Delaware)
Oak Mountain Products, LLC (Delaware)
Ocotillo Windpower, LP (Delaware)
Ohio River Valley Propane, LLC (Delaware)
P.I.D.C. Aguaytia, L.L.C. (Delaware)
Pacific Power Holdings No 1. B.V. (Netherlands)
Pan Service Company (Delaware)
PanEnergy Corp (Delaware)
Peru Energy Holdings, LLC (Delaware)
Pioneer Transmission, LLC (Indiana)
Proyecto de Autoabastecimiento La Silla, S. de R.L. de C.V. (Mexico)

Duke Energy Kentucky, Inc. (Kentucky)
Duke Energy Lee II, LLC (Delaware)
Duke Energy Marketing America, LLC (Delaware)
Duke Energy Marketing Corp. (Nevada)
Duke Energy Marketing Limited Partnership (Alberta, Canada)
Duke Energy Merchants, LLC (Delaware)
Duke Energy Moapa, LLC (Delaware)
Duke Energy Murray Operating, LLC (Delaware)
Duke Energy North America, LLC (Delaware)
Duke Energy Ohio, Inc. (Ohio)
Duke Energy One, Inc. (Delaware)
Duke Energy Peru Holdings S.R.L. (Peru)
Duke Energy Receivables Finance Company, LLC (Delaware)
Duke Energy Registration Services, Inc. (Delaware)
Duke Energy Retail Sales, LLC (Delaware)
Duke Energy Royal, LLC (Delaware)
Duke Energy Services Canada ULC (British Columbia, Canada)
Duke Energy Services, Inc. (Delaware)
Duke Energy Trading and Marketing, L.L.C. (Delaware)
Duke Energy Transmission Holding Company, LLC (Delaware)
Duke Energy Vermillion II, LLC (Delaware)
Duke Energy Washington II, LLC (Delaware)
Duke Engineering & Services (Europe) Inc. (Delaware)
Duke Engineering & Services International, Inc. (Cayman Islands)
Duke Investments, LLC (Delaware)
Duke Project Services, Inc. (North Carolina)
Duke Supply Network, LLC (Delaware)
Duke Technologies, Inc. (Delaware)
Duke Trading Do Brasil Ltda. (Brazil)
Duke Ventures II, LLC (Delaware)

Sandy River Timber, LLC (South Carolina)
Seahorse do Brasil Servicos Maritimos Ltda. (Brazil)
Searchlight Wind Energy LLC (Nevada)
SEC Bellefonte SD Solar One, LLC (Delaware)
SEC BESD Solar One, LLC (Delaware)
Silver Sage Windpower, LLC (Delaware)
Solar Star North Carolina I, LLC (Delaware)
Solar Star North Carolina II, LLC (Delaware)
South Construction Company, Inc. (Indiana)
Southern Power Company (North Carolina)
Spruce Mountain Investments, LLC (Delaware)
Spruce Mountain Products, LLC (Delaware)
SUEZ-DEGS of Lansing, LLC (Delaware)
SUEZ-DEGS of Orlando LLC (Delaware)
Sugartree Timber, LLC (Delaware)
SYNCAP II, LLC (Delaware)
Taylorsville, Solar, LLC (Delaware)
TBP Properties, LLC (South Carolina)
TE Happy Jack, LLC (Delaware)
TE Notrees, LLC (Delaware)
TE Ocotillo, LLC (Delaware)
Teak Mountain Products, LLC (Delaware)
TEC Aguaytia, Ltd. (Bermuda)
Termoselva S. R. L. (Peru)
Texas Eastern (Bermuda) Ltd. (Bermuda)
Texas Eastern Arabian Ltd. (Bermuda)
The Duke Energy Foundation (North Carolina)
Three Buttes Windpower, LLC (Delaware)
Top of the World Wind Energy LLC (Delaware)
Top of the World Wind Energy Holdings LLC (Delaware)
TRES Timber, LLC (South Carolina)
Tri-State Improvement Company (Ohio)
Wateree Power Company (South Carolina)
Western Carolina Power Company (North Carolina)
Willow Creek Wind Energy LLC (Delaware)
Willow Mountain Products, LLC (Delaware)

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-002

REQUEST:

For all reports and forms currently filed with the SEC by Duke Energy and Progress, provide separately for each company a list of all reports or forms routinely filed with the SEC. Include the name of the report or form, the reference number (i.e., Form 10-K, Form 8-K, etc.), a brief description of the information provided in the report or form, a statement of how frequently the report or form is filed with the SEC, and explain whether the report or form will continue to be filled with the SEC after completion of the proposed merger.

RESPONSE:

See Attachment Staff-DR-01-002 (Duke)

See Attachment Staff-DR-01-002 (Progress)

PERSON RESPONSIBLE: James E. Rogers (Duke)
Holly H. Wenger (Progress)

ITEM 2: REPORTS/FORMS ROUTINELY FILED WITH THE SEC BY PROGRESS ENERGY, INC.

SUBMISSION TYPE	DESCRIPTION	FREQUENCY OF FILING	WILL FORM CONTINUE TO BE FILED POST-MERGER?
8-K	Current report of unscheduled material events specified by the SEC and for reports of non-public information required to be disclosed by Regulation FD	As needed	Following the completion of the merger, this form will no longer be filed with the SEC by Progress Energy, Inc
10-K	Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934	Annually	Following the completion of the merger, this form will no longer be filed with the SEC by Progress Energy, Inc.
10-Q	Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934	Quarterly	Following the completion of the merger, this form will no longer be filed with the SEC by Progress Energy, Inc.
11-K	Annual report of employee stock purchase, savings and similar plans	Annually	Following the completion of the merger, this form will no longer be filed with the SEC by Progress Energy, Inc.
DEF 14A	Definitive proxy statement	Annually	Following the completion of the merger, this form will no longer be filed with the SEC by Progress Energy, Inc.
DEFA14A	Definitive additional materials related to an upcoming shareholder vote	Annually	Following the completion of the merger, this form will no longer be filed with the SEC by Progress Energy, Inc.

DUKE ENERGY FILINGS

Form Number	Name	Description	Frequency	Post-merger Filing
10-K	Annual report	Filing under the Securities Exchange Act of 1934, as amended (the "Exchange Act") providing detailed financial information on a company as of the end of their last fiscal year, as well as a comprehensive overview of the business and material issues of the company	Annually	Yes
10-Q	Quarterly report	Filing under the Exchange Act providing financial information on the company for a certain quarter and an update on all material issues of the company	Quarterly	Yes
11-K	Annual report of employee stock plan	Filing under the Exchange Act providing annual financial information on employee stock purchase, savings and similar plans	Annually	Yes
424	Prospectus	Filing under the Securities Act of 1933, as amended (the "Securities Act"), containing the basic business and financial information with respect to a particular securities offering	As needed	Yes
425	Prospectus	Filing under Securities Act Rule 425 of certain prospectuses and communications in connection with business combination transactions	As needed	Yes
8-K	Current report	Filing under the Exchange Act which reports the occurrence of any material events or corporate change that would be important to investors	As needed	Yes
DEF 14A	Definitive proxy statement	Filing under Schedule 14A of the Exchange Act which provides shareholders with the information necessary to enable them to vote at an annual or special shareholder meeting.	Annually	Yes
DEFA 14A	Additional definitive proxy soliciting materials	Filing under Schedule 14A of the Exchange Act of additional materials accompanying the definitive proxy statement such as the Notice of the meeting	Annually	Yes
FWP	Free writing prospectus	Filing under the Securities Act of any written	As needed	Yes

		communication associated with the offer to sell a security used as a supplement to a formal prospectus		
S-3	Registration statement	Filing under the Securities Act to register securities to be offered in certain specified transactions	As needed	Yes
S-3ASR	Automatic shelf registration statement	Filing under the Securities Act to register securities of well-known seasoned issuers, which are companies that have a market value of $700 million or meet certain other thresholds provided by the SEC. Both Duke Energy and Progress Energy are well-known seasoned issuers	As needed	Yes
S-4	Registration statement	Filing under the Securities Act to register securities to be issued in connection with business combination transactions	As needed	Yes
S-8	Registration statement	Filing under the Securities Act to register securities to be offered to employees pursuant to certain employee plans	As needed	Yes

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-003

REQUEST:

~~Concerning change or control payments:~~

a. Indicate the number of directors, executives, officers, or employees of Duke Energy who will be eligible for change of control payments as a result of the proposed merger. Also provide the total estimated amount of the change of control payments for Duke Energy.
b. I dentify the directors, executives, offices, or employees of Duke Kentucky who will be eligible for change of control payments as a result of the proposed merger. Also provide the estimated amount of the change of control payment for each Duke Kentucky director, executive, officer, or employee.
c. Describe the mechanisms in Duke Kentucky's accounting system that will prevent the recording of any change of control payments – either directly, indirectly, or allocated – on Duke Kentucky's books and records.

RESPONSE:

a. The proposed merger will not constitute a "change in control" within the meaning of the compensation and benefit plans maintained by Duke Energy, Duke Energy Kentucky, and their respective affiliates. As a result, the directors, executives, officers, and employees of Duke Energy, Duke Energy Kentucky, and their respective affiliates will not be eligible for change of control payments as a result of the proposed merger. Please see Direct testimony of Julie S. Janson at page 42.

b. N/A

c. There will be no change in control payments made directly by Duke Energy Kentucky. The procedures and processes for allocating costs are subject to approvals and therefore any change of control payments that might be allocated to Duke Energy Kentucky would be detected during processing. Further, monthly assessments of actual vs. budgeted costs are performed and any costs that were allocated but not budgeted would be detected during the variance analysis process.

PERSON RESPONSIBLE: (a,b) Jennifer Weber
(c) Danny Wiles

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-004

REQUEST:

Explain how Duke Energy and Progress will reorganize shared services (such as accounting, human resources, procurement and IT) to accomplish the savings and transparencies desired in the synergies of the proposed merger.

RESPONSE:

Duke Energy and Progress are currently in the process of analyzing the shared services to be provided post-merger. As addressed in page 14 of the Direct Testimony of William Don Wathen Jr., it is anticipated that the Progress service company will be consolidated into the Duke Energy service company sometime in the future, but it is unknown at this time when this consolidation will occur.

While the integration of shared services functions is expected to result in net synergies savings over time, it is premature to assert how the underlying functions will be organized after the close of the merger. As of May 2011, integration teams are in the process of gathering facts and comparing the operations of Duke Energy and Progress Energy. Organizational design decisions – such as the combination of the Duke Energy and Progress Energy shared services functions – will be made at a later date.

PERSON RESPONSIBLE: AR Mullinax (Duke)
Andrew D. Cox (Progress)

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-005

REQUEST:

As to the synergies of the proposed merger, explain whether there will be any expected or foreseeable savings as to licensing agreements, such as for software applications, which are used by both Duke Energy and Progress

RESPONSE:

Yes, savings of this nature are expected. See also response to Staff DR-01-004.

PERSON RESPONSIBLE: AR Mullinax (Andrew D. Cox-Progress)

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-006

REQUEST:

Refer to page 7, paragraph 15, of the Joint Application. Identify the unscrubbed coal generation capacity that will exist upon completion of the proposed transaction, the age of the facilities and the owner(s) thereof.

RESPONSE:

See Attachment Staff-DR-01-006 (Duke)

And Attachment Staff-DR-01-006 (Progress).

PERSON RESPONSIBLE: Barry Pulskamp (Duke)
William D. Johnson (Progress)

Duke Energy
Unscrubbed Coal Generation Capacity

5/2/2011

Station	Unit	Spring/Fall Unit Rating (MW)	Summer Unit Rating (MW)	Winter Unit Rating (MW)	Commercial Operation Date	Unit Ownership	Operated by:	Station Total (MW)	
Buck	3	75	75	76	7/1/1941	100%	Duke Energy Carolinas	377	MW Buck Station Capacity
	4	38	38	39	9/1/1942	100%	Duke Energy Carolinas		
	5	126	128	131	9/1/1953	100%	Duke Energy Carolinas		
	6	128	128	131	12/1/1953	100%	Duke Energy Carolinas		
Cliffside	1	38	38	38	7/1/1940	100%	Duke Energy Carolinas	750	MW Cliffside Station Capacity
	2	38	38	38	8/1/1940	100%	Duke Energy Carolinas		
	3	61	61	61	5/1/1948	100%	Duke Energy Carolinas		
	4	61	61	61	10/1/1948	100%	Duke Energy Carolinas		
	5**	562	562	562	6/1/1972	100%	Duke Energy Carolinas		
Dan River	1	67	67	67	12/1/1949	100%	Duke Energy Carolinas	276	MW Dan River Station Capacity
	2	67	67	67	3/1/1950	100%	Duke Energy Carolinas		
	3	142	142	142	8/1/1955	100%	Duke Energy Carolinas		
Edwardsport	6	40	40	40	7/1/1944	100%	Duke Energy Indiana	160	MW Edwardsport Station Capacity
	7	45	45	45	1/1/1949	100%	Duke Energy Indiana		
	8	75	75	75	12/1/1951	100%	Duke Energy Indiana		
Gallagher	1	140	140	140	6/15/1958	100%	Duke Energy Indiana	560	MW Gallagher Station Capacity
	2	140	140	140	12/1/1958	100%	Duke Energy Indiana		
	3	140	140	140	4/15/1960	100%	Duke Energy Indiana		
	4	140	140	140	3/1/1961	100%	Duke Energy Indiana		
Lee	1	100	100	100	3/1/1951	100%	Duke Energy Carolinas	370	MW Lee Station Capacity
	2	100	100	100	7/1/1951	100%	Duke Energy Carolinas		
	3	170	170	170	12/1/1952	100%	Duke Energy Carolinas		
Riverbend	4	94	94	94	10/1/1952	100%	Duke Energy Carolinas	454	MW Riverbend Station Capacity
	5	94	94	94	11/1/1952	100%	Duke Energy Carolinas		
	6	133	133	133	8/1/1954	100%	Duke Energy Carolinas		
	7	133	133	133	11/1/1954	100%	Duke Energy Carolinas		
Wabash River	2	85	85	85	8/1/1953	100%	Duke Energy Indiana	668	MW Wabash River Station Capacity
	3	85	85	85	9/1/1954	100%	Duke Energy Indiana		
	4	85	85	85	1/1/1955	100%	Duke Energy Indiana		
	5	95	95	95	5/1/1956	100%	Duke Energy Indiana		
	6	318	318	318	8/1/1968	100%	Duke Energy Indiana		
Miami Fort	6	163	163	163	11/1/1960	100%	Duke Energy Kentucky	163	MW Miami Fort Station Capacity
Beckjord	1	94	94	94	6/23/1952	100%	Duke Energy Ohio*	862	MW Beckjord Station Capacity
	2	94	94	94	10/9/1953	100%	Duke Energy Ohio*		
	3	125	128	128	11/30/1954	100%	Duke Energy Ohio*		
	4	150	150	150	7/11/1958	100%	Duke Energy Ohio*		
	5	238	238	238	12/21/1962	100%	Duke Energy Ohio*		
	6	158	155	158	7/1/1969	37.5% Duke Energy 50% DP&L 12.5% AEP	Duke Energy Ohio*		

TOTAL CAPACITY = 4650 MW Duke Energy Share (MW)

**Cliffside Unit 5 will be a scrubbed unit once Cliffside 6 Modernization Project comes online
*Duke Energy Ohio and DP&L is Non-Regulated
Duke Share (MW) - Info received from Scott Haag
Info from Scott Haag

Florida Power Corporation

Crystal River Unit No. 1
440.5 MW maximum nameplate
Commercial in-service date of 1966.

Crystal River Unit No. 2
523.8 MW maximum nameplate
Commercial in-service date of 1969.

Carolina Power & Light Company

Robinson Unit No. 1
187.85 MW maximum nameplate
Commercial in-service date of 1960.

Cape Fear (two units)
328.475 MW maximum nameplate
Commercial in-service date of 1956

Lee (three units)
446.672 MW maximum nameplate
Commercial in-service dates of 1952 – 1962

Sutton (three units)
671.618 MW maximum nameplate
Commercial in-service dates of 1954 – 1972

Weatherspoon (three units)
165.5 MW maximum nameplate
Commercial in-service dates of 1949 – 1952

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 25, 2011

STAFF-DR-01-007

REQUEST:

Refer to Exhibit I of the application, which contains draft of the amended affiliate agreements to which the Progress companies are to be added as parties. Provide copies of the five existing agreements with all proposed changes tracked.

RESPONSE:

Please see Staff DR-01-007 Attachments (1-5).

PERSON RESPONSIBLE: William Don Wathen Jr.

UTILITY MONEY POOL AGREEMENT

This UTILITY MONEY POOL AGREEMENT (this "Agreement") is made and entered into as of ________________ ("Effective Date") by and among Duke Energy Corporation, a Delaware corporation ("Duke Energy"), Cinergy Corp., a Delaware corporation ("Cinergy"), Duke Energy Carolinas, LLC, a North Carolina limited liability company ("DE-Carolinas"), ~~Duke Energy Indiana, Inc., an Indiana corporation ("DE-Indiana")~~, Duke Energy Ohio, Inc., an Ohio corporation ("DE-Ohio"), Duke Energy Kentucky, Inc., a Kentucky corporation ("DE-Kentucky"), Miami Power Corporation, an Indiana corporation ("Miami"), KO Transmission Company, a Kentucky corporation ("KO"), Progress Energy, Inc., a North Carolina corporation ("Progress Energy"), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., a North Carolina corporation ("PE-North Carolina"), Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation ("PE-Florida"), Progress Energy Service Company, LLC, a North Carolina corporation ("Progress Services"), and Duke Energy Business Services LLC, a Delaware limited liability company ("DEBS~~uke Services~~"), (each a "party" and collectively, the "parties"). For purposes of this Agreement Progress Services and DEBS shall each collectively be referred to as Duke Services. This Agreement supersedes and replaces in its entirety the Utility Money Pool Agreement dated November 1, 2008.

Recitals

Each of DE-Carolinas, DE-Indiana, DE-Ohio, DE-Kentucky, PE-Florida, PE-North Carolina and Miami is a public utility company and a subsidiary company of Duke Energy. DEBS~~uke Services~~ and Progress Services are ~~is a~~ subsidiary service companies~~y~~ of Duke Energy. KO is a nonutility company and a subsidiary company of DE-Ohio.

The parties from time to time have need to borrow funds on a short-term basis. Some of the parties from time to time have funds available to loan on a short-term basis. The parties desire to establish a cash management program (the "Utility Money Pool") to coordinate and provide for certain of their short-term cash and working capital requirements.

~~The terms of this Agreement are substantially similar to a prior agreement entered into among the parties as of January 2, 2007, and the purpose of this Agreement is to reflect the merger of Duke Energy Shared Services, Inc. into Duke Energy Business Services LLC.~~

NOW THEREFORE, in consideration of the premises, and the mutual promises set forth herein, the parties hereto agree as follows:

ARTICLE I
CONTRIBUTIONS AND BORROWINGS

rates of interest, is used to fund loans through the Utility Money Pool, each borrowing party will borrow pro rata from each fund source in the same proportion that the amount of funds provided by that fund source bears to the total amount of short-term funds available to the Utility Money Pool.

Section 1.4 Authorization. (a) Each loan shall be authorized by the lending party's chief financial officer or treasurer, or by a designee thereof.

(b) All borrowings from the Utility Money Pool shall be authorized by the borrowing party's chief financial officer or treasurer, or by a designee thereof. No party shall be required to effect a borrowing through the Utility Money Pool if such party determines that it can (and is authorized to) effect such borrowing at lower cost from other sources, including but not limited to directly from banks or through the sale of its own commercial paper.

Section 1.5 Interest. Each party receiving a loan shall accrue interest monthly on the unpaid principal amount of such loan to the Utility Money Pool from the date of such loan until such principal amount shall be paid in full.

(a) If only Internal Funds comprise the funds available in the Utility Money Pool, the interest rate applicable to loans of such Internal Funds shall be the CD yield equivalent of the 30-day Federal Reserve "AA" Industrial Commercial Paper Composite Rate (or, if no such Composite Rate is established for that day, then the applicable rate shall be the Composite Rate for the next preceding day for which such Composite Rate was established).

(b) If only External Funds comprise the funds available in the Utility Money Pool, the interest rate applicable to loans of such External Funds shall be equal to the lending party's cost for such External Funds (or, if more than one party had made available External Funds on such day, the applicable interest rate shall be a composite rate, equal to the weighted average of the cost incurred by the respective parties for such External Funds).

(c) In cases where both Internal Funds and External Funds are concurrently borrowed through the Utility Money Pool, the rate applicable to all loans comprised of such "blended" funds shall be a composite rate, equal to the weighted average of the (i) cost of all Internal Funds contributed by parties (as determined pursuant to Section 1.5(a) above) and (ii) the cost of all such External Funds (as determined pursuant to Section 1.5(b) above); provided, that in circumstances where Internal Funds and External Funds are available for loans through the Utility Money Pool, loans may be made exclusively from Internal Funds or External Funds, rather than from a "blend" of such funds, to the extent it is expected that such loans would result in a lower cost of borrowing.

Section 1.6 Certain Costs. The cost of compensating balances and fees paid to banks to maintain credit lines by parties lending External Funds to the Utility Money Pool shall initially be paid by the party maintaining such line. A portion of such costs

Section 2.3 Allocation of Interest Income and Investment Earnings. The interest income and other investment income earned by the Utility Money Pool on loans and investment of surplus funds will be allocated among the parties in accordance with the proportion each party's contribution of funds in the Utility Money Pool bears to the total amount of funds in the Utility Money Pool and the cost of any External Funds provided to the Utility Money Pool by such party. Interest and other investment earnings will be computed on a daily basis and settled once per month.

Section 2.4 Event of Default. If any party shall generally not pay its debts as such debts become due, or shall admit in writing its inability to pay its debts generally, or shall make a general assignment for the benefit of creditors, or any proceeding shall be instituted by or against any party seeking to adjudicate it a bankrupt or insolvent, then the other parties may declare the unpaid principal amount of any loans to such party, and all interest thereon, to be forthwith due and payable and all such amounts shall forthwith become due and payable.

ARTICLE III
MISCELLANEOUS

Section 3.1 Amendments. No amendment to this Agreement shall be effective unless set forth in writing and executed by each of the parties. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any affected state public utility commission for its review or otherwise, the parties shall comply in all respects with any such requirements.

Section 3.2 Legal Responsibility. Nothing herein contained shall render any party liable for the obligations of any other party hereunder and the rights, obligations and liabilities of the parties are several in accordance with their respective obligations, and not joint.

Section 3.3 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of New York, without regard to conflicts of laws principles thereof.

Section 3.4 Effective Date; Term. This Agreement shall become effective on the Effective Date and shall continue in full force and effect until terminated by the parties. This Agreement may be terminated and thereafter will be of no further force and effect upon the mutual consent in writing of all of the parties.

Section 3.5 Entire Agreement. This Agreement contains the entire agreement between and among the parties with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto~~(including without limitation that certain Utility Money Pool Agreement between and among the parties dated as of January 2, 2007)~~. Any oral or written statements, representations, promises, negotiations or

IN WITNESS WHEREOF, the undersigned companies have duly caused this Utility Money Pool Agreement to be executed on their behalf on the Effective Date above by the undersigned thereunto duly authorized.

~~DUKE ENERGY CORPORATION~~

By:________________________
Richard G. Beach
Assistant Corporate Secretary

CINERGY CORP.

By:________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY BUSINESS SERVICES LLC

By:________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY CAROLINAS, LLC

By:________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY INDIANA, INC.

By:________________________
Richard G. Beach
Assistant Secretary

PROGRESS ENERGY, INC.

By:___________________________

CAROLINA POWER & LIGHT COMPANY D/B/A
PROGRESS ENERGY CAROLINAS, INC.

By: ___________________________

FLORIDA POWER CORPORATION D/B/A PROGRESS
ENERGY FLORIDA, INC.

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By:___________________________

PROGRESS ENERGY SERVICE COMPANY, LLC

By:___________________________

DUKE ENERGY CORPORATION AND CONSENTING MEMBERS OF ITS CONSOLIDATED GROUP

~~SECOND~~THIRD ~~AMENDED~~ AGREEMENT FOR FILING CONSOLIDATED INCOME TAX RETURNS AND FOR ALLOCATION OF CONSOLIDATED INCOME TAX LIABILITIES AND BENEFITS

Duke Energy Corporation, a Delaware corporation ("Duke Energy"), and its Members hereby agree as of ~~October 1, 2008~~_____________ to join annually in the filing of a consolidated Federal income tax return and to allocate the consolidated Federal income tax liabilities and benefits among the Members of the Consolidated Group in accordance with the provisions of this ~~Second Amended~~ Agreement ("Agreement"). ~~The purpose of this Second Amendment, which is effective as of November 1, 2008_____________, is to clarify certain terms, reflect the parties' name changes which occurred since the prior agreement, and revise the list of signatories.~~ This Agreement supersedes and replaces in its entirety the Agreement for Filing Consolidated Income Tax Returns and for Allocation of Consolidated Income and Tax Liabilities and Benefits dated October 1, 2008.

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1. DEFINITIONS

"Affiliate" means a corporation, or a company that is treated as a corporation or a company wholly owned by an entity treated as a corporation that is disregarded for purposes of U.S. federal income taxation, other than the common parent which is a Member of the Affiliated Group.

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"Affiliated Group" means a group of corporations, or companies that are treated as corporations or disregarded for purposes of U.S. federal income taxation, as defined in Internal Revenue Code ("IRC") section 1504 and the regulations enacted thereunder,

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"Consolidated Group" means a group filing (or required to file) consolidated returns for the tax year.

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"Consolidated tax" is the aggregate current Federal income tax liability for the Consolidated Group for a tax year shown on the consolidated Federal income tax return, including any adjustments thereto, or as described in section 5 hereof.

"Corporate taxable income" is the positive taxable income of an Affiliate for a tax year, computed as though such company had filed a separate return on the same basis as used in the consolidated return, except that dividend income from Affiliates shall be disregarded, and other intercompany transactions, eliminated in consolidation, shall be given appropriate effect.

"Corporate taxable loss" is the taxable loss of an Affiliate for a tax year, computed as though such entity had filed a Separate return on the same basis as used in the consolidated return, except that dividend income from Affiliates shall be disregarded, and other intercompany transactions, eliminated in consolidation, shall be given appropriate effect.

"Corporate tax credit" is a negative separate regular tax of an Affiliate for a tax year, equal to the amount by which the consolidated regular tax is reduced by including the Corporate taxable loss of such Affiliate in the consolidated tax return.

"Environmental Tax" The Superfund Amendments and Reauthorization Act of 1986 imposed a new Environmental Tax. The tax was imposed only for the years beginning after December 31, 1986 and before January 1, 1996. The environmental tax was equal to 0.12 percent ($12 of tax per $10,000 of alternative minimum taxable income ("AMTI")) of the excess of AMTI over $2,000,000 and was imposed whether or not the taxpayer was subject to the alternative minimum tax. The Environmental Tax is included in this Agreement for the purposes of any refund on liability with respect to those years when it was in effect.

"Group" means a group of Affiliates as defined in IRC section 1504

"Separate return" is the tax liability calculated on the taxable income or loss of an Affiliate as though such entity were not a Member of a Consolidated Group.

"Member" is an Affiliate, including a Regulated Business as indicated in section 3 herein, which is part of the Affiliated Group as defined in IRC section 1504 that files consolidated tax returns and agrees to be subject to this Agreement.

These definitions shall apply, as appropriate, in the context of the regular income tax and the Alternative Minimum Tax ("AMT") unless otherwise indicated in the Agreement.

2. FILING OF RETURNS

A U.S. consolidated federal income tax return shall be filed by Duke Energy as the common parent for the tax year ended December 31, 2008, and for each subsequent taxable period for which the Affiliated Group is required or permitted to do so. Each Member of the Affiliated Group consents to the filing by Duke Energy of consolidated federal income tax returns for all taxable periods in which it is eligible to be a member of the Affiliated Group. Duke Energy and each Member of the Affiliated Group agrees to execute and file such consents, elections and other documents, and to take such other action as may be necessary, required or appropriate for the proper filing of such returns. Duke Energy will timely pay the Affiliated Group's federal income tax liability for each taxable year

3 REGULATED BUSINESSES OPERATING IN LLC OR LP FORM

For purposes of allocating the consolidated federal and state tax liabilities and tax benefits under this Agreement, each business operating as a LLC, or LP that is subject to the rules and regulations of the Federal Energy Regulatory Commission or state utilities commissions (hereinafter, a "Regulated Business") shall be considered a member of the Consolidated Group, and shall be responsible for its allocable share of taxable income (or shall be entitled to a credit for its allocable share of tax loss), as set forth in Sections 4 through 7 hereof. For purposes of this Agreement, the determination of a Regulated Business's allocable share shall be made (i) as if such Regulated Business was a taxable or regarded entity for U.S. federal income tax purposes and (ii) utilizing the separate "taxable income" method.

4. ALLOCATION PROCEDURES FOR CONSOLIDATED FEDERAL INCOME TAXES

For all taxable periods, Duke Energy shall calculate the consolidated federal income tax liability (including, if applicable, alternative minimum tax liability) of the Affiliated Group for the period. The Members agree that their respective shares of the Consolidated tax liability for each year shall be an amount equal to the amount determined under the income method in accordance with IRC 1552(a)(2)[1], with the absorption of tax benefits determined under the percentage method in accordance with Treas. Reg. section 1.1502-33(d)(3)[2], using 100% as the applicable percentage for allocation of any excess of a member's Separate return liability over that determined under the income method. To the extent that the Consolidated Group federal income tax liability is reduced by a loss or tax credit available to it as a result of the inclusion of a Member in the consolidated federal income tax return, Duke Energy shall make a payment or an inter-company account adjustment for the amount of the benefit to the Member as determined in accordance with this section.

To illustrate the above, the Consolidated tax liability shall be allocated among the Members of the Group utilizing the separate return "taxable income" allocation method attributable to each Member, in the following manner:

---

[1] Under IRC 1551(a)(2), tax liability is allocated to the several members of the group on the basis of the percentage of the total tax which the tax of such member if computed on a separate return would bear to the total amount of the taxes for all members of the group so computed

[2] The percentage method under this regulation "allocates tax liability based on the absorption of tax attributes, without taking into account the ability of any member to subsequently absorb its own tax attributes The allocation under this method is in addition to the allocation under section 1552"

a) Each Member, which has a Corporate taxable loss, will be entitled to a Corporate tax credit equal to the amount by which the consolidated regular income tax is reduced by including the corporate tax loss of such Member in the consolidated tax return. The Members having corporate taxable income will be allocated an amount of regular income tax liability equal to the sum of the consolidated regular tax liability and the Corporate tax credits allocated to the Members having corporate tax losses based on the ratio that each such Member's Corporate taxable income bears to the total corporate taxable income of all Members having Corporate taxable income.

If the aggregate of the Members' Corporate taxable losses are not entirely utilized on the current year's consolidated return, the consolidated carryback or carryforward of such losses to the applicable taxable year(s) will be allocated to each Member having a Corporate taxable loss in the ratio that such Member's separate Corporate tax loss bears to the total corporate tax losses of all Members having Corporate taxable losses.

b) The consolidated Environmental Tax will be allocated among the Members of the Group by applying the procedures set forth in subsection a) above, except that the basis for allocation will be Alternative Minimum Taxable Income ("AMTI") rather than regular corporate taxable income.

c) The consolidated AMT will be allocated among the Members in accordance with the procedures and principles set forth in Proposed Treasury Regulation section 1.1502-55 in the form such Regulation existed on the date on which this Agreement was executed.

d) Tax benefits such as general business credits, foreign tax benefits, or other tax credits shall be apportioned directly to those Members whose investments or contributions generated the credit or benefit.

If the credit or benefit cannot be entirely utilized to offset current Consolidated tax, the consolidated credit carryback or carryforward shall be apportioned to those Members whose investments or contributions generated the credit or benefit in proportion to the relative amounts of credits or benefits generated by each Member.

e) If the amount of Consolidated tax allocated to any Member under this Agreement, as determined above, exceeds the separate return tax of such Member, such excess shall be reallocated among those Members whose allocated tax liability is less than the amount of their respective separate return tax liabilities. The reallocation shall be proportionate to the respective reductions in separate return tax liability of such Members. Any remaining unallocated tax liability shall be assigned to Duke Energy. The term "tax" and "tax liability" used in the subsection shall include regular tax, Environmental Tax and AMT.

5. TAX PAYMENTS AND COLLECTIONS FOR ALLOCATIONS

Duke Energy shall make any calculations on behalf of the Members necessary to comply with the estimated tax provisions of the Internal Revenue Code of 1986 as amended (the "Code"). Based on such calculations, Duke Energy shall charge or refund to the Members appropriate amounts at intervals consistent with the dates indicated by Code section 6655. Duke Energy shall be responsible for paying to the Internal Revenue Service the consolidated current Federal income tax liability.

After filing the consolidated Federal income tax return and allocating the Consolidated tax liability among the Members, Duke Energy and the Members agree to settle between them the difference, if any, between the allocable federal income tax liability as determined under this Agreement and the sum of all payments or inter-company adjustments previously made relating to that tax year by means of actual payments, in the case of Regulated companies, or adjustments to their respective inter-company accounts.

6 ALLOCATION OF STATE TAX LIABILITIES OR BENEFITS

State and local income tax liabilities will be allocated, where appropriate, among Members in accordance with principles similar to those employed in the Agreement for the allocation of consolidated Federal income tax liability.

7 TAX RETURN ADJUSTMENTS

In the event the consolidated tax return is subsequently adjusted by the Internal Revenue Service, state tax authorities, amended returns, claims for refund, or otherwise, such adjustments shall be reflected in the same manner as though they had formed part of the original consolidated return. Interest paid or received, and penalties imposed on account of any adjustment will be allocated to the responsible Member.

8. NEW MEMBERS

If, at any time, a corporation becomes a Member of the affiliated group, the parties hereto agree that such new Member shall become a party to this Agreement by executing a duplicate copy of this Agreement. Unless otherwise specified, such new Member shall have similar rights and obligations of all other Members under this Agreement, effective as of the day they become a member of the Affiliated Group that elects to file a consolidated return.

9 MEMBERS LEAVING THE AFFILIATED GROUP

In the event that any Member of the Affiliated Group at any time leaves the Group and, under any applicable statutory provision or regulation, that Member is assigned and is deemed to take with it all or a portion of any of the tax attributes (including, but not limited to, net operating losses, credit carryforwards, and Minimum Tax Credit carryforwards) of the Affiliated Group, then, to the extent the amount of the attributes so assigned differs from the amount of such attributes previously allocated to such Member under this Agreement, the leaving Member shall appropriately settle with the Group. Such settlement shall consist of payment on a dollar-for-dollar basis for all differences in credits and, in the case of net operating loss differences, in an amount computed by reference to the highest marginal corporate tax rate. The settlement amounts shall be allocated among the remaining Members of the Group in proportion to the relative level of attributes possessed by each Member and the attributes of each Member shall be adjusted accordingly.

10. SUCCESSORS, ASSIGNS

The provisions and terms of the Agreement shall be binding on and inure to the benefit of any successor or assignee by reason of merger, acquisition of assets, or otherwise, of any of the Members hereto.

11. AMENDMENTS AND TERMINATION

This Agreement may be amended at any time by the written agreement of the parties hereto at the date of such amendment and may be terminated at any time by the written consent of all such parties.

12. GOVERNING LAW

This Agreement is made under the law of the State of Delaware, which law shall be controlling in all matters relating to the interpretation, construction, or enforcement hereof.

13. EFFECTIVE DATE

This ~~Second Amended~~ Agreement is effective for the allocation of the current Federal income tax liabilities of the Members for the consolidated tax year 2011~~09~~ and all subsequent years until this ~~Second Amended~~ Agreement is revised in writing.

The above procedure for apportioning the consolidated annual net current federal and state tax liabilities and tax benefits of Duke Energy and consenting Members of its Consolidated Group have been agreed to by each of the below listed Members of the Consolidated Group as evidenced by the signature of an officer of each entity.

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on its behalf by an appropriate officer thereunto duly authorized.

DUKE ENERGY CORPORATION

By:____________________
Richard G. Beach
Assistant Corporate Secretary

CINERGY CORP.

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY BUSINESS SERVICES LLC

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY OHIO, INC.

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY INDIANA, INC.

By:____________________
Richard G. Beach
Assistant Secretary

SOUTH CONSTRUCTION COMPANY, INC.

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY KENTUCKY, INC.

By:______________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY CAROLINAS, LLC

By:______________________
Richard G. Beach
Assistant Secretary

MIAMI POWER CORPORATION

By:______________________
Richard G. Beach
Assistant Secretary

TRI-STATE IMPROVEMENT COMPANY

By:______________________
Richard G. Beach
Assistant Secretary

KO TRANSMISSION COMPANY

By:______________________
Richard G. Beach
Assistant Secretary

CINERGY INVESTMENTS, INC.

By:______________________
George Dwight, II
Assistant Secretary

DUKE COMMUNICATIONS HOLDINGS, INC.
~~(formerly Cinergy Telecommunications Holding Company, Inc.)~~

By:____________________
Richard G. Beach
Assistant Secretary

CINERGY TECHNOLOGY, INC.

By:____________________
Richard G. Beach
Assistant Secretary

CINERGY UK, INC.

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY ENGINEERING, INC.
~~(formerly Cinergy Engineering, Inc.)~~

By:____________________
George Dwight, II
Assistant Secretary

DUKE ENERGY GENERATION SERVICES HOLDING COMPANY, INC.
~~(formerly Cinergy Solutions Holding Company, Inc.)~~

By:____________________
George Dwight, II
Assistant Secretary

DUKE-CADENCE, INC.

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY COMMERCIAL ENTERPRISE ~~CINERGY CAPITAL & TRADING~~, INC.

By:______________________
George Dwight, II
Assistant Secretary

CINERGY GLOBAL POWER, INC.

By:______________________
Joseph E. Lentz, Jr.
Vice President

CINERGY GLOBAL RESOURCES, INC.

By:______________________
Joseph E. Lentz, Jr.
Vice President

DUKE–RELIANT RESOURCES, INC.

By:______________________
Richard G. Beach
Assistant Secretary

CINERGY-CENTRUS COMMUNICATIONS, INC.

By:______________________
Richard G. Beach
Assistant Secretary

CINERGY-CENTRUS, INC.

By:______________________
Richard G. Beach
Assistant Secretary

CINERGY GLOBAL HOLDINGS, INC.

By ______________________
James D. Duncan, Jr.
Vice President

~~CINERGY GLOBAL ELY, INC.~~

~~By: ______________________~~
~~James D. Duncan, Jr.~~
~~Vice President~~

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DEGS OF TUSCOLA, INC

By: ______________________
George Dwight, II
Assistant Secretary

DUKE ENERGY ONE, INC.
~~(formerly Cinergy One, Inc.)~~

By: ______________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY COMMEEMRCIAL ASSET MANAGEMENT, ~~CINERGY POWER INVESTMENTS,~~ INC.

By: ______________________
Joseph E. Lentz, Jr.
Vice President

DUKE ENERGY GENERATION SERVICES, INC.
~~(formerly Cinergy Solutions, Inc.)~~

By: ______________________
George Dwight, II
Assistant Secretary

DUKE TECHNOLOGIES, INC.
~~(formerly Cinergy Technologies, Inc.)~~

By: ______________________
Richard G. Beach
Assistant Secretary

~~CINERGY TWO, INC~~

~~By: ____________________~~
~~Richard G. Beach~~
~~Assistant Secretary~~

CINERGY WHOLESALE ENERGY, INC.

By: ____________________
Joseph E. Lentz, Jr.
Vice President

DUKETEC, LLC
(*formerly CinTec LLC*)

By: ____________________
Richard G. Beach
Assistant Secretary

CINERGY RETAIL POWER LIMITED, INC.

By: ____________________
Richard G. Beach
Assistant Secretary

CINERGY RETAIL POWER GENERAL, INC.

By: ____________________
Joseph E. Lentz, Jr.
Vice President

DEGS OF PHILADELPHIA, LLC

By: ____________________
George Dwight, II
Assistant Secretary

CINFUEL RESOURCES, INC.

By: ____________________

George Dwight, II
Assistant Secretary

CINERGY CLIMATE CHANGE INVESTMENTS, LLC

By:____________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY RETAIL SALES, LLC
~~(formerly Cinergy Retail Sales, LLC)~~

By:____________________
Richard G. Beach
Assistant Secretary

DEGS OF SAN DIEGO, INC.
~~(formerly Cinergy Solutions of San Diego, Inc.)~~

By:____________________
George Dwight, II
Assistant Secretary

CINERGY SOLUTIONS UTILITY, INC.

By:____________________
Richard G. Beach
Assistant Secretary

BISON INSURANCE COMPANY LIMITED

By:____________________
George V. Brown
President and Chief Executive Officer

CALDWELL POWER COMPANY

By:____________________
Richard G. Beach
Assistant Secretary

CATAWBA MANUFACTURING AND ELECTRIC POWER COMPANY

By:________________________
Richard G. Beach
Assistant Secretary

CLAIBORNE ENERGY SERVICES, INC.

By:________________________
Richard G. Beach
Assistant Secretary

DE NUCLEAR ENGINEERING, INC.

By:________________________
~~Julia S. Janson~~
Secretary

DETMI MANAGEMENT, INC.

By:________________________
Richard G. Beach
Assistant Secretary

DIXILYN-FIELD DRILLING COMPANY

By: ________________________
Richard G. Beach
Assistant Secretary

~~DUKE COMMUNICATION SERVICES, INC.~~

~~By:________________________~~
~~Julia S. Janson~~
~~Assistant Secretary~~

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~~DUKE ENERGY ALLOWANCE MANAGEMENT, LLC~~

~~By:________________________~~
~~Sherwood L. Love~~

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~~Vice President~~

DUKE ENERGY FOSSIL-HYDRO CALIFORNIA, INC.

By:________________________
Richard G. Beach
Assistant Secretary

~~DUKE ENERGY GLOBAL MARKETS, INC.~~

~~By:________________________~~
~~Richard G. Beach~~
~~Assistant Secretary~~

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DUKE ENERGY GROUP HOLDINGS, LLC

By:________________________
~~Javier Gonzalez~~
Assistant Secretary

DUKE ENERGY MARKETING AMERICA, LLC

By:________________________
Greer E. Mendelow
Assistant Secretary

DUKE ENERGY POWER GENERATING, LLC

By:________________________

Assistant Secretary

DUKE ENERGY MARKETING CORP

By:________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY REGISTRATION SERVICES, INC.

By:________________________
Julia S. Janson

Secretary

DUKE ENERGY SERVICES, INC.

By:________________________
Richard G. Beach
Assistant Secretary

DUKE ENGINEERING & SERVICES (EUROPE) INC.

By :________________________
Richard G. Beach
Assistant Secretary

DUKE PROJECT SERVICES, INC.

By: ________________________
Richard G. Beach
Assistant Secretary

DUKE VENTURES, LLC

By: ________________________
Richard G. Beach
Assistant Secretary

DUKENET VENTURECO, INC.

By: ________________________

Assistant Secretary

EASTOVER LAND COMPANY

By:________________________
Richard G. Beach
Assistant Secretary

EASTOVER MINING COMPANY

By:________________________
Richard G. Beach

Assistant Secretary

ENERGY PIPELINES INTERNATIONAL COMPANY

By: ______________________
Richard G. Beach
Assistant Secretary

GREENVILLE GAS AND ELECTRIC LIGHT AND POWER COMPANY

By: ______________________
Richard G. Beach
Assistant Secretary

~~MP SUPPLY, INC.~~

~~By: ______________________~~
~~Julia S. Jansen~~
~~Secretary~~

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NORTHSOUTH INSURANCE COMPANY LIMITED

By: ______________________
George V. Brown
President and Chief Executive Officer

Duke Energy China Corp.~~PAN SERVICE COMPANY~~

By: ______________________
Richard G. Beach
Assistant Secretary

PANENERGY CORP

By: ______________________
Richard G. Beach
Assistant Secretary

~~SOUTHEASTERN ENERGY SERVICES, INC~~

~~By:________________________~~
~~Steven L. Sheck~~
~~Secretary~~

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SOUTHERN POWER COMPANY

By:________________________
Richard G. Beach
Assistant Secretary

WESTERN CAROLINA POWER COMPANY

By:________________________
Richard G. Beach
Assistant Secretary

~~DUKE JAVA, INC.~~

~~By:________________________~~
~~Javier Gonzalez~~
~~Assistant Secretary~~

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~~DENA ASSET PARTNERS, L.P.~~
~~(by *DENA Partners Holding, LLC, its General Partner*~~

~~By:________________________~~
~~Richard G. Beach~~
~~Secretary~~

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~~DUKENET COMMUNICATIONS, LLC~~

~~By:________________________~~
~~Richard G. Beach~~
~~Assistant Secretary~~

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WATEREE POWER COMPANY

By:________________________
Richard G. Beach

Assistant Secretary

~~DEGS BIOGAS, INC.~~

~~By:____________________~~
~~George Dwight, II~~
~~Assistant Secretary~~

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DUKE ENERGY TRANSMISSION HOLDING COMPANY, LLC

By:________________________
Richard G. Beach
Assistant Secretary

Catamount Energy Corporation

By:________________________
Richard G. Beach
Assistant Secretary

Catamount Rumford Corporation

By:________________________
Richard G. Beach
Assistant Secretary

Catamount Sweetwater Corporation

By:________________________
Richard G. Beach
Assistant Secretary

CEC UK1 Holding Corporation

By:________________________
Richard G. Beach
Assistant Secretary

CEC UK2 Holding Corporation

By:________________________
Richard G. Beach
Assistant Secretary

Duke Energy Corporate Services, Inc.

By:_________________________
Richard G. Beach
Assistant Secretary

Equinox Vermont Corporation

By:_________________________
Richard G. Beach
Assistant Secretary

Progress Energy, Inc.

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By:_________________________

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.

By:_________________________

Florida Power Corporation d/b/a Progress Energy Florida, Inc.

By:_________________________

CaroFinancial, Inc.

By:_________________________

CaroFund, Inc.

By:_________________________

Capitan Corporation

By:_________________________

Progress Energy EnviroTree, Inc.

By: ______________________

Strategic Resource Solutions Corp.

By: ______________________

Progress Ventures Holdings, Inc.

By: ______________________

Progress Ventures, Inc.

By: ______________________

Florida Progress Corporation

By: ______________________

Florida Progress Funding Corporation

By: ______________________

Progress Capital Holdings, Inc.

By: ______________________

PIH, Inc.

By: ______________________

PIH Tax Credit Fund III, Inc.

By: ______________________

PIH Tax Credit Fund IV, Inc.

By: ______________________

PIH Tax Credit Fund V, Inc.

By: ______________________

Progress Telecommunications Corporation

By: ______________________

Progress Fuels Corporation

By: ______________________

PC Property Holdings, Inc.

By: ______________________

Progress Synfuel Holdings, Inc.

By: ______________________

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INTERCOMPANY ASSET TRANSFER AGREEMENT

This **Intercompany Asset Transfer Agreement** (this "Agreement") is made and entered into as of ~~December 22, 2008~~______________ (the "Effective Date") by and among Duke Energy Carolinas, LLC, a North Carolina limited liability company ("DE Carolinas"), Duke Energy Ohio, Inc., an Ohio corporation ("DE Ohio"), Duke Energy Indiana, Inc., an Indiana corporation ("DE Indiana"), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., a North Carolina corporation, Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation, and Duke Energy Kentucky, Inc., a Kentucky corporation ("DE Kentucky") (collectively the "Operating Companies" and, individually, an "Operating Company"). This Agreement supersedes and replaces in its entirety the Intercompany Asset Transfer Agreement dated December 22, 2008.

WITNESSETH:

WHEREAS, Duke Energy Corporation ("Duke Energy") is a Delaware corporation;

WHEREAS, each Operating Company is a subsidiary of Duke Energy and a public utility company;

WHEREAS, in the ordinary course of their businesses, the Operating Companies maintain inventory and other assets for the operation and maintenance of their respective electric utility, and with respect to DE Ohio and DE Kentucky, gas utility, businesses; and

WHEREAS, subject to the terms and conditions herein set forth, and taking into consideration the Operating Companies' utility responsibilities, each Operating Company is willing, upon request from time to time, to transfer Assets, as defined herein, to each other Operating Company, as each shall request from each other.

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1. TRANSFER OF ASSETS

Section 1.1 Transfer. Upon request from one party ("Recipient"), the other party ("Transferor") shall transfer to the Recipient those Assets requested by Recipient, provided that (i) Transferor believes, in its reasonable judgment, that such transfer will not jeopardize Transferor's ability to render electric utility service to its customers consistent with Good Utility Practice and, for DE Carolinas, such a transfer is consistent with the priority of service condition approved by the NCUC by Order dated October 30, 2006, in Docket No. E-7, Sub 810; (ii) the Cost of any shipment of transmission- or generation-related item(s) does not exceed $10,000,000; (iii) DE Carolinas shall not transfer any Asset hereunder in contravention of S.C. Code Ann. § 58-27-1300; (iii) DE Kentucky shall not transfer any Asset hereunder in contravention of KRS 278.218; (iv) DE Carolinas shall not transact with DE Ohio's generation operation under this Agreement and shall not transact with DE Kentucky or DE Indiana for purposes of circumventing or avoiding this prohibition: and (v) DE Carolinas shall not transfer or take receipt of any transmission transformers or other equipment under this Agreement other than transmission-related equipment that may be used on/with transformers within a range of voltages or regardless of voltage. "Assets" means parts inventory, capital spares, equipment and other goods except for the following: coal; natural gas; fuel oil used for electric power generation; emission allowances; electric power; and environmental control reagents. "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in the United States during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, method, or acts generally accepted in the region

Section 1.2 Compensation. Except to the extent otherwise required by Section 482 of the Internal Revenue Code or analogous state tax law, Recipient shall compensate Transferor for any Assets transferred hereunder at Cost; provided however that any transfers of electric generation-related Assets between DE Ohio, on the one hand, and DE Indiana, or DE Kentucky on the other hand, will be priced in accordance with Federal Energy Regulatory Commission's ("FERC") affiliate transaction pricing requirements. Accordingly, generation-related Assets transferred from DE Indiana or DE Kentucky to DE Ohio shall be priced at the greater of Cost or market, and generation-related Assets transferred from DE Ohio to DE Indiana or DE Kentucky shall be priced at no more than market. "Cost" means (i) for items of inventory accounted for in the FERC Uniform System of Accounts account 154 ("Inventory Items"), the average unit price of such Inventory Items as recorded on the books of the Transferor, plus stores, freight, handling, and other applicable costs, and (ii) for assets other than Inventory Items, net book value.

Alternatively, to the extent that an Asset may be transferred under this Agreement, the Transferor and Recipient may agree that the Asset transferred to the Recipient be replaced in kind. In this event, Transferor and Recipient shall agree to the timing of such replacement, and other necessary terms and conditions, and such in-kind replacement shall be deemed a transferred Asset for all purposes hereunder.

Section 1.3 Payment. Each Operating Company shall reasonably cooperate with each other Operating Company to record billings and payments required hereunder in their common accounting systems.

Section 1.4 Delivery; Title and Risk of Loss. The parties shall cooperate in providing transportation equipment necessary to deliver the Assets to the Recipient. Assets will be delivered FOB transportation equipment at the Transferor's location where such Assets reside ("Shipping Point"). All costs of transportation, including the cost of transporting in-kind replacement Assets to Transferor, shall be borne by the Recipient. Title to and risk of loss of the transferred Assets shall pass from the Transferor to the Recipient at the Shipping Point.

ARTICLE 2. WARRANTIES

Section 2.1 Warranties. Each Operating Company, as Transferor, warrants that it will have good and marketable title to the Assets transferred hereunder. Further, each Operating Company, as Transferor, warrants that it shall obtain release of any liens or other encumbrances on the transferred Assets within a reasonable time. ALL ASSETS TRANSFERRED HEREUNDER ARE BEING SOLD "AS IS, WHERE IS" AND WITHOUT ANY WARRANTY AS TO ITS CONDITION, INCLUDING WITHOUT ANY WARRANTY AS TO MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

Section 2.2 Disclaimer. WITH RESPECT TO ANY ASSETS TRANSFERRED HEREUNDER, EACH OPERATING COMPANY AS TRANSFEROR MAKES NO WARRANTY OR REPRESENTATION OTHER THAN AS SET FORTH IN SECTION 2.1, AND THE PARTIES HERETO HEREBY AGREE THAT NO OTHER WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE), SHALL BE APPLICABLE TO SUCH ASSETS. THE PARTIES FURTHER AGREE THAT THE REMEDIES STATED HEREIN ARE EXCLUSIVE AND SHALL CONSTITUTE THE SOLE AND EXCLUSIVE REMEDY OF ANY PARTY HERETO FOR A FAILURE BY ANY OTHER PARTY HERETO TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

ARTICLE 3. INDEMNIFICATION

Section 3.1 Indemnification; Limitation of Liability.

(a) Subject to subparagraph (b) of this Section 3.1, each party (the "Indemnifying Party") shall release, defend, indemnify and hold harmless the other party (the "Indemnified Party"), including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any loss, liability, claim, damage, expense (including costs of investigation and defense and reasonable attorneys' fees), whether or not involving a third-party claim, incurred or sustained by or against any such Indemnified Party arising, directly or indirectly, from or in connection with Indemnifying Party's negligence or willful misconduct in the performance of its obligations hereunder.

(b) Notwithstanding any other provision hereof, each party's total liability hereunder with respect to any Assets shall be limited to the amount actually paid to Transferor for such Assets for which the liability arises, and under no circumstances shall Transferor be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

Section 3.2 Procedure for Indemnification. Within 15 business days after receipt by an Indemnified Party of notice of any claim or the commencement of any action, suit, litigation or other proceeding against it (a "Proceeding") with respect to which it is eligible for indemnification hereunder, the Indemnified Party shall notify the Indemnifying Party thereof in writing (it being understood that failure so to notify the Indemnifying Party shall not relieve the latter of its indemnification obligation, unless the Indemnifying Party establishes that defense thereof has been prejudiced by such failure). Thereafter, the Indemnifying Party shall be entitled to participate in such Proceeding and, at its election upon notice to such Indemnified Party and at its expense, to assume the defense of such Proceeding. Without the prior written consent of such Indemnified Party, Indemnifying Party shall not enter into any settlement of any third-party claim that would lead to liability or create any financial or other obligation on the part of such Indemnified Party for which such Indemnified Party is not entitled to indemnification hereunder. If such Indemnified Party has given timely notice to Indemnifying Party of the commencement of such Proceeding, but Indemnifying Party has not, within 15 business days after receipt of such notice, given notice to Indemnified Party of its election to assume the defense thereof, Indemnifying Party shall be bound by any determination made in such Proceeding or any compromise or settlement made by Indemnified Party. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice from the applicable Indemnified Party to Indemnifying Party.

ARTICLE 4. MISCELLANEOUS

Section 4.1 Amendments. Any amendments to this Agreement shall be in writing executed by each of the parties hereto. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any affected state public utility commission for its review or otherwise, each Operating Company shall comply in all respects with any such requirements.

Section 4.2 Effective Date; Term. This Agreement shall become effective on the Effective Date and shall continue in full force and effect until terminated by either party upon not less than 30 days prior written notice to the other party. This Agreement may be terminated and thereafter be of no further force and effect upon the mutual consent of the parties hereto.

Section 4.3 Entire Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto. Any oral or written statements, representations, promises, negotiations or agreements, whether prior hereto or concurrently herewith, are superseded by and merged into this Agreement.

Section 4.4 Severability. If any provision of this Agreement or any application thereof shall be determined to be invalid or unenforceable, the remainder of this Agreement and any other application thereof shall not be affected thereby.

Section 4.5 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any party hereto without the prior written consent of the other party. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 4.6 Governing Law. This Agreement shall be construed and enforced under and in accordance with the laws of the State of New York, without regard to conflicts of laws principles.

Section 4.7 Captions, etc. The captions and headings used in this Agreement are for convenience of reference only and shall not affect the construction to be accorded any of the provisions hereof. As used in this Agreement, "hereof," "hereunder," "herein," "hereto," and words of like import refer to this Agreement as a whole and not to any particular section or other paragraph or subparagraph thereof.

Section 4.8 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed a duplicate original hereof, but all of which shall be deemed one and the same Agreement.

Section 4.9 DE Carolinas Conditions. In addition to the terms and conditions set forth herein, with respect to DE Carolinas, the provisions set out in Exhibit A are hereby incorporated herein by reference. In addition, except with respect to the pricing of Asset transfers as set forth herein, DE Carolinas' participation in this Agreement is explicitly subject to the Regulatory Conditions and Code of Conduct approved by the NCUC in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued March 24, 2006, in Docket No. E-7, Sub 795

("Merger Order"), as such Regulatory Conditions and Code of Conduct may be amended from time to time. In accordance with Regulatory Condition 9 as approved in the Merger Order, nothing in this Agreement shall be construed or interpreted so as to commit DE Carolinas, or to involve DE Carolinas in, joint planning, coordination, or operation of generation, transmission, or distribution facilities with one or more affiliates nor shall it be interpreted as otherwise altering DE Carolinas' obligations with respect to the Regulatory Conditions approved in the Merger Order. In the event of a conflict between the provisions of this Agreement and the Regulatory Conditions and Code, the Regulatory Conditions and Code shall govern, except as altered by the Commission by Order for this Agreement.

Section 4.10 DE Indiana Conditions. DE Indiana agrees and acknowledges that in accordance with its Affiliate Standards, Section II O (i) it will make Assets available to non-affiliated wholesale power marketers under the same terms, conditions and prices, and at the same time, as it makes Assets available to a DE Ohio's wholesale power marketing function, and (ii) it will process all requests for Assets from DE Ohio's wholesale power marketing function and non-affiliated wholesale power marketers on a non-discriminatory basis.

Section 4.11 Regulatory Approvals. This Agreement is expressly contingent on the receipt of all regulatory approvals or waivers deemed necessary by the parties.

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on its behalf by an appropriate officer thereunto duly authorized.

Duke Energy Carolinas, LLC.

By: ______________________
Richard G. Beach
Assistant Secretary

Duke Energy Indiana, Inc.

By: ______________________
Richard G. Beach
Assistant Secretary

Duke Energy Ohio, Inc.

By: ______________________
Richard G. Beach
Assistant Secretary

Duke Energy Kentucky, Inc.

By: ______________________
Richard G. Beach
Assistant Secretary

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
By: ______________________

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
By: ______________________

EXHIBIT A

DE CAROLINAS CONDITIONS

In connection with the North Carolina Utilities Commission ("NCUC") approval of the Merger in NCUC Docket No. E-7, Sub 795, the NCUC imposed certain Regulatory Conditions ("Regulatory Conditions") and adopted a revised Code of Conduct governing transactions between DE Carolinas and its affiliates ("Code of Conduct"). Pursuant to the Regulatory Conditions and Code of Conduct, the following provisions are applicable to DE Carolinas and considered to be incorporated into the Intercompany Asset Transfer Agreement filed in Docket No. E-7, Sub 844:

~~(1) DE Carolinas' participation in this Agreement is voluntary. DE Carolinas is not~~ obligated to take or provide services or make any purchases or sales pursuant to this Agreement, and DE Carolinas may elect to discontinue its participation in this Agreement at its election after giving notice under Section 4.2 of the Agreement.

(2) DE Carolinas may not make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder.

(3) DE Carolinas may not seek to reflect in rates any (i) costs incurred under this Agreement exceeding the amount allowed by the NCUC or (ii) revenue level earned under this Agreement less than the amount imputed by the NCUC; and

(4) DE Carolinas will not assert in any forum that the NCUC's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is preempted and will bear the full risk of any preemptive effects of federal law with respect to this Agreement.

(5) DE Carolinas' authority to engage in transfers pursuant to this Agreement at cost-based pricing as an exception to its Code of Conduct is limited to single Asset transfers where the Cost of such Asset does not exceed $100,000. The annual aggregate limit on (i) transfers of Assets hereunder at cost-based pricing as an exception to DE Carolinas' Code of Conduct; plus (ii) transactions/services rendered to and from DE Carolinas under Section III(D)(3)(d) of the Code of Conduct, shall be $8.5 million on a DE Carolinas total company basis. Any transfers of Assets above the single item/transaction limit shall be priced according to Sections III(D)(3)(a) and III(D)(3)(b) of DE Carolinas' Code of Conduct. Any proposed transfers over the aggregate annual limit are outside the scope of this Agreement and will be filed with the Commission pursuant to N.C. Gen. Stat. § 62-153.

(6) DE Carolinas shall retain appropriate documentation verifying compliance with the terms hereof for Public Staff and NCUC review.

(7) DE Carolinas shall submit to the NCUC for approval any changes in the terms and conditions of this Agreement having or likely to have a material effect on DE Carolinas.

(8) DE Carolinas shall file a separate detailed report in this docket with respect to all transfers engaged in by Duke pursuant to the Agreement.

(9) DE Carolinas acknowledges and agrees that for ratemaking purposes, NCUC approval of DE Carolinas' participation in this Agreement does not constitute approval of the amount of compensation paid with respect to transactions pursuant to the Agreement, and that the authority granted by the NCUC is without prejudice to the right of any party to take issue with any provision of the Agreement or with any transaction pursuant thereto in a future proceeding.

~~THIRD AMENDED AND RESTATED~~ OPERATING COMPANIES SERVICE AGREEMENT

This ~~Third Amended and Restated~~ Operating Companies Service Agreement (this "Agreement"), dated ~~May 18, 2010~~ (the "Effective Date"), by and among Duke Energy Carolinas, LLC, a North Carolina limited liability company ("DE-Carolinas"), Duke Energy Ohio, Inc., , an Ohio corporation ("DE-Ohio"), Duke Energy Indiana, Inc., an Indiana corporation ("DE-Indiana"), Duke Energy Kentucky, Inc., a Kentucky corporation ("DE-Kentucky"), ~~and~~ Miami Power Corporation, an Indiana corporation ("Miami"). Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PE-North Carolina"), a North Carolina corporation, and Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation ("PE-Florida"). ~~and collectively with~~ DE-Carolinas, DE-Ohio, DE-Indiana, ~~and~~ DE-Kentucky, Miami, PE-North Carolina and PE-Florida are referred to collectively as the "Operating Companies" and, individually, an "Operating Company"~~)~~ supersedes and replaces in its entirety the Operating Company Service Agreement dated May 18, 2010.~~supersedes and restates in its entirety the Second Amended and Restated Operating Companies Service Agreement entered into by the Operating Companies dated September 1, 2008.~~

WITNESSETH:

WHEREAS, Duke Energy Corporation ("Duke Energy") is a Delaware corporation;

WHEREAS, each Operating Company is a subsidiary of Duke Energy and a public utility company;

WHEREAS, in the ordinary course of their businesses, Operating Companies maintain organizations of employees with technical expertise in matters affecting public utility companies and related businesses and own or acquire related equipment, facilities, properties and other resources; and

WHEREAS, subject to the terms and conditions herein set forth, and taking into consideration the parties' utility responsibilities or primary business operations, as the case may be, the parties hereto are willing, upon request from time to time, to perform such services, and in connection therewith to make available such equipment, facilities, properties and other resources, as they shall request from each other;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1. PROVISION OF SERVICES; LOANED EMPLOYEES

Section 1.1 Provision of Services.

(a) Upon receipt by a party hereto (in such capacity, a "Service Provider") of a written request in substantially the form attached hereto as Exhibit A (a "Service Request") from another party hereto (in such capacity, a "Client Company") for the provision to such Client Company of such services as are specified therein, including if applicable use of any related equipment, facilities, properties or other resources (collectively, "Services"), the Service Provider, if in its sole discretion it has available the personnel or other resources needed to perform the Service Request without impairment of its utility responsibilities or business operations, as the case may be, shall furnish such Services to the Client Company at such times, for such periods and in such manner as the Client Company shall have so requested and otherwise in accordance with the provisions hereof.

(b) For purposes of this Agreement, "Services" may include, but shall not be limited to, services in such areas as engineering and construction; operations and maintenance; installation services; equipment testing; generation technical support; environmental, health and safety; and procurement services.

(c) "Services" may also include the use of assets, equipment and facilities, provided the Client Company compensates the Service Provider for such use in accordance with Article 3.

(d) For the avoidance of doubt, affiliate transactions involving sales or other transfers of assets, goods, energy commodities (including electricity, natural gas, coal and other combustible fuels) or thermal energy products are outside the scope of this Agreement.

Section 1.2 Loaned Employees.

(a) If specifically requested in connection with the provision of Services, Service Provider shall loan one or more of its employees to such Client Company, provided that such loan shall not, in the sole discretion of Service Provider, interfere with or impair Service Provider's utility responsibilities or business operations, as the case may be. After the commencement thereof, any such loaned employees may be withdrawn by Service Provider from tasks duly assigned by Client Company, prior to completion thereof as contemplated in the associated Service Request, only with the consent of Client Company (which shall not be unreasonably withheld or delayed), except in the event of a demonstrable emergency requiring the use of any such employees in another capacity for Service Provider.

(b) While performing work on behalf of Client Company, any such loaned employees shall be under its supervision and control, and Client Company shall be responsible for their actions to the same extent as though such persons were its employees (it being understood that such persons shall nevertheless remain employees of Service Provider and nothing herein shall be construed as creating an employer-employee relationship between any Client Company and any loaned employees). Accordingly, for the duration of any such loan, Service Provider shall continue to provide its loaned employees with the same payroll, pension, savings, tax withholding, unemployment, bookkeeping and other personnel support services then being provided by Service Provider to its other employees.

ARTICLE 2. SERVICE REQUESTS

Section 2.1 Procedure. All Services (including any loans of employees) (i) shall be performed in accordance with Service Requests issued by or on behalf of Client Company and accepted by Service Provider and (ii) shall be assigned to applicable activities, processes, projects, responsibility centers or on other appropriate bases to enable specific work to be properly assigned.

Service Requests shall be as specific as practicable in defining the Services requested. Client Company shall have the right from time to time to amend or rescind any Service Request, *provided* that (a) Service Provider consents to any amendment that results in a material change in the scope of Services to be provided, (b) the costs associated with an amended or rescinded Service Request shall include the costs incurred by Service Provider as a result of such amendment or rescission, and (c) no amendment or rescission of a Service Request shall release Client Company from any liability for costs already incurred or contracted for by Service Provider pursuant to the original Service Request, regardless of whether any labor or the furnishing of any property or other resources has been commenced or completed.

ARTICLE 3. COMPENSATION FOR SERVICES

Section 3.1 Cost of Services. As compensation for any Services rendered to it pursuant to this Agreement, Client Company shall pay to Service Provider the Cost thereof, except to the extent otherwise required by Section 482 of the Internal Revenue Code; provided, however, that Services provided to or by DE-Carolinas shall be priced in accordance with DE-Carolinas's North Carolina Code of Conduct approved by the North Carolina Utilities Commission; and further provided that with respect to Services relating to wholesale merchant or electric generation functions, such Services provided by DE Carolinas, DE Indiana, or DE Kentucky to DE Ohio shall be priced at the greater of Cost or market, and such Services provided by DE Ohio to DE Carolinas, DE Indiana, or DE Kentucky shall be priced at no more than market. "Costs" means the sum of (i) direct costs, (ii) indirect costs and (iii) costs of capital. As soon as practicable after the close of each month, Service Provider shall render to each Client Company a statement reflecting the billing information necessary to identify the costs charged for that month. By the last day of each month, Client Company shall remit to Service Provider all charges billed to it. For avoidance of doubt, the Service Provider and each Client Company may satisfy the foregoing requirement by recording billings and payments required hereunder in their common accounting systems without rendering paper or electronic monthly statements or remitting cash payments.

Section 3.2 Exception. In the event any Services to be rendered under this Agreement are to be provided to or from DE-Carolinas in accordance with DE-Carolinas's North Carolina Code of Conduct at anything other than fully embedded cost as described above, then prior to entering into the transaction, DE-Indiana, DE-Kentucky or DE-Ohio, whichever is applicable, shall provide 30 days written notice to the respective state commission staffs and state consumer representatives explaining the proposed transaction, including the benefits of the transaction. If no objection is received within 30 days, then the transaction may proceed. If one or more third parties object to the transaction in writing within 30 days, then DE-Indiana, DE-Kentucky or DE-Ohio, whichever is applicable, must seek specific state commission approval of the transaction prior to entering into the transaction.

ARTICLE 4. LIMITATION OF LIABILITY; INDEMNIFICATION

Section 4.1 Limitation of Liability/Services. In performing Services pursuant to Section 1.1 hereof, Service Provider will exercise due care to assure that the Services are performed in a workmanlike manner in accordance with the specifications set forth in the applicable Service Request and consistent with any applicable legal standards. The sole and exclusive responsibility of Service Provider for any deficiency therein shall be promptly to correct or repair such deficiency or to re-perform such Services, in either case at no additional cost to Client Company, so that the Services fully conform to the standards described in the first sentence of this Section 4.1. No Service Provider makes any other warranty with respect to the provision of Services, and each Client Company agrees to accept any Services without further warranty of any nature.

Section 4.2 Limitation of Liability/Loaned Employees. In furnishing Services under Section 1.2 hereof (i.e., involving loaned employees), neither the Service Provider, nor any officer, director, employee or agent thereof, shall have any responsibility whatever to any Client Company receiving such Services, and Client Company specifically releases Service Provider and such persons, on account of any claims, liabilities, injuries, damages or other consequences arising in connection with the provision of such Services under any theory of liability, whether in contract, tort (including negligence or strict liability) or otherwise, it being understood and agreed that any such loaned employees are made available without warranty as to their suitability or expertise.

Section 4.3 Disclaimer. WITH RESPECT TO ANY SERVICES PROVIDED UNDER THIS AGREEMENT, THE SERVICE PROVIDER THEREOF MAKES NO WARRANTY OR REPRESENTATION OTHER THAN AS SET FORTH IN SECTION 4.1, AND THE PARTIES HERETO HEREBY AGREE THAT NO OTHER WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE), SHALL BE APPLICABLE TO THE PROVISION OF ANY SUCH SERVICES. THE PARTIES FURTHER AGREE THAT THE REMEDIES STATED HEREIN ARE EXCLUSIVE AND SHALL CONSTITUTE THE SOLE AND EXCLUSIVE REMEDY OF ANY PARTY HERETO FOR A FAILURE BY ANY OTHER PARTY HERETO TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

Section 4.4 Indemnification.

(a) Subject to subparagraph (b) of this Section 4.4, Service Provider shall release, defend, indemnify and hold harmless each Client Company, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any loss, liability, claim, damage, expense (including costs of investigation and defense and reasonable attorneys' fees), whether or not involving a third-party claim, incurred or sustained by or against any such Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services.

(b) Notwithstanding any other provision hereof, Service Provider's total liability hereunder with respect to any specific Services shall be limited to the amount actually paid to Service Provider for its performance of the specific Services for which the liability arises, and under no circumstances shall Service Provider be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

Section 4.5 Procedure for Indemnification. Within 15 business days after receipt by any Client Company of notice of any claim or the commencement of any action, suit, litigation or other proceeding against it (a "Proceeding") with respect to which it is eligible for indemnification hereunder, such Client Company shall notify Service Provider thereof in writing (it being understood that failure so to notify Service Provider shall not relieve the latter of its indemnification obligation, unless Service Provider establishes that defense thereof has been prejudiced by such failure). Thereafter, Service Provider shall be entitled to participate in such Proceeding and, at its election upon notice to such Client Company and at its expense, to assume the defense of such Proceeding. Without the prior written consent of such Client Company, Service Provider shall not enter into any settlement of any third-party claim that would lead to liability or create any financial or other obligation on the part of such Client Company for which it such Client Company is not entitled to indemnification hereunder. If such Client Company has given timely notice to Service Provider of the commencement of such Proceeding, but Service Provider has not, within 15 business days after receipt of such notice, given notice to Client Company of its election to assume the defense thereof, Service Provider shall be bound by any determination made in such Proceeding or any compromise or settlement made by Client Company. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice from the applicable Client Company to Service Provider.

ARTICLE 5. MISCELLANEOUS

Section 5.1 Amendments. Any amendments to this Agreement shall be in writing executed by each of the parties hereto. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any affected state public utility commission for its review or otherwise, each Operating Company shall comply in all respects with any such requirements.

Section 5.2 Effective Date; Term. This Agreement shall become effective on the Effective Date and shall continue in full force and effect as to each party until terminated by any party, as to itself only, upon not less than 30 days prior written notice to the other parties hereto. Any such termination of parties shall not be deemed an amendment hereto. This Agreement may be terminated and thereafter be of no further force and effect upon the mutual consent of all of the parties hereto.

Section 5.3 Entire Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto. Any oral or written statements, representations, promises, negotiations or agreements, whether prior hereto or concurrently herewith, are superseded by and merged into this Agreement.

Section 5.4 Severability. If any provision of this Agreement or any application thereof shall be determined to be invalid or unenforceable, the remainder of this Agreement and any other application thereof shall not be affected thereby.

Section 5.5 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of each of the other parties. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 5.6 Governing Law. This Agreement shall be construed and enforced under and in accordance with the laws of the State of New York, without regard to conflicts of laws principles.

Section 5.7 Captions, etc. The captions and headings used in this Agreement are for convenience of reference only and shall not affect the construction to be accorded any of the provisions hereof. As used in this Agreement, "hereof," "hereunder," "herein," "hereto," and words of like import refer to this Agreement as a whole and not to any particular section or other paragraph or subparagraph thereof.

Section 5.8 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed a duplicate original hereof, but all of which shall be deemed one and the same Agreement.

Section 5.9 DE-Carolinas Conditions. In addition to the terms and conditions set forth herein, with respect to DE-Carolinas, the provisions set out in Appendix B are hereby incorporated herein by reference. In addition, except with respect to the pricing of Services as set forth herein, DE-Carolinas' participation in this Agreement is explicitly subject to the Regulatory Conditions and Code of Conduct approved by the NCUC in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued March 24, 2006, in Docket No. E-7, Sub 795, as such Regulatory Conditions and Code of Conduct may be amended from time to time.

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on its behalf by an appropriate officer thereunto duly authorized.

Duke Energy Carolinas, LLC

By: ______________________

Richard G. Beach
Assistant Secretary

Duke Energy Ohio, Inc.

By: ______________________

Richard G. Beach
Assistant Secretary

Duke Energy Indiana, Inc.

By: ________________________
Richard G. Beach
Assistant Secretary

Duke Energy Kentucky, Inc.

By: ________________________
Richard G. Beach
Assistant Secretary

Miami Power Corporation

By: ________________________
Richard G. Beach
Assistant Secretary

Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.
By: ________________________

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
By: ________________________

Exhibit A

eForms

Folder Name efr148v1-000142
Status New

Service Request for Affiliates

* Red Asterisk indicates required fields

Service Provider

* Service Provider [ ] Selec
* Legal Approval Representative [ ] Selec

Proposed Service

* Description of Proposed Service

Please Provide Basis for Estimated Costs include # of employees requested and amount of time requested

* Estimated Costs (Numbers only no commas or decimals) $0
* Scheduled Start Date
* Scheduled Completio Date

Client Company

* Client Company [ ] Selec

Accounting Codes (FMIS/BDMS) of the Client Company Receiving the Service

*** Process/Work Code(s) OR Project & Activities (FMIS only) OR GL Account must be entered

n/a / Corp Number
* Operating Unit / Line of Business
* Resp. Center / Center
* Process / Work Code(s)
* Project
* Activity
* GL Account

Confirmation of Service Provider Utility Responsibilities by Service Provider Approver

* [ ] Check this box to confirm that this Service Request will not result in impairment of Service Provider's utility responsibilities or operations

Miscellaneous Comments

Comments

Comments Log

Exhibit A

Attachments

Help

Filename	Size

Approver Selection

The approvers should be appropriate according to the Delegation of Authority (DOA) matrix

Route To:	Name		Phone	Status
* Client Company		Select		
* Service Provider		Select		
* Legal				

Submitter Details

Created by	Pahulski, Michael J	Created on	3/9/2008 11:09:03 AM
* Phone	(513) 419-1803		
Last Modified by		Last Modified	

Exhibit B

DE-CAROLINAS CONDITIONS

1. In connection with the North Carolina Utilities Commission ("NCUC") approval of the Merger in NCUC Docket No. E-7, Sub 795, the NCUC adopted certain Regulatory Conditions ("Regulatory Conditions") and a revised Code of Conduct governing transactions between DE-Carolinas and its affiliates ("Code of Conduct"). Pursuant to the Regulatory Conditions and Code of Conduct, the following provisions are applicable to DE-Carolinas:

(a) DE-Carolinas's participation in this Agreement is voluntary. DE-Carolinas is not obligated to take or provide services or make any purchases or sales pursuant to this Agreement, and DE-Carolinas may elect to discontinue its participation in this Agreement at its election after giving notice under Section 6.2 of the Agreement.

(b) DE-Carolinas may not make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder.

(c) DE-Carolinas may not seek to reflect in rates any (i) costs incurred under this Agreement exceeding the amount allowed by the NCUC or (ii) revenue level earned under this Agreement less than the amount imputed by the NCUC; and

(d) Except to the extent that requesting FERC review and authorization pursuant to 1275(b) of Subtitle F in Title XII of PUHCA 2005, as provided in Regulatory Condition 21, may be determined to have preemptive effect under the law, DE-Carolinas will not assert in any forum that the NCUC's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is preempted and will bear the full risk of any preemptive effects of federal law with respect to this Agreement.

2. <u>Transfers by DE-Carolinas</u>. With respect to the transfer by DE-Carolinas under this Agreement of the control of, operational responsibility for, or ownership of any DE-Carolinas assets used for the generation, transmission or distribution of electric power to its North Carolina retail customers with a gross book value in excess of ten million dollars, the following shall apply: (a) DE-Carolinas may not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations and orders of the NCUC promulgated thereunder; and (b) DE-Carolinas may not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

3. <u>Access to DE-Carolinas Information</u>. Any Operating Company providing Services to DE-Carolinas pursuant to this Agreement, including any loaned employees under Section 1.2 of the Agreement, shall be permitted to have access to DE-Carolinas Customer Information and Confidential Systems Operation Information, as those terms are defined in the Code of Conduct, to the extent necessary for the performance of such Services; provided that such Operating Company shall take reasonable steps to protect the confidentiality of such Information.

~~SECOND AMENDED AND RESTATED~~

SERVICE COMPANY
UTILITY SERVICE AGREEMENT

This ~~Second Amended and Restated~~ Service Company Utility Service Agreement (this "~~Second Amended and Restated Service Agreement" or~~ "Agreement")), dated ~~September 1, 2008~~___________ (the "Effective Date") is by and among Duke Energy Carolinas, LLC ("DE-Carolinas"), a North Carolina limited liability company, Duke Energy Ohio, Inc., an Ohio corporation ("DE-Ohio"), Duke Energy Indiana, Inc., an Indiana corporation ("DE-Indiana"), Duke Energy Kentucky, Inc., a Kentucky corporation ("DE-Kentucky"), Miami Power Corporation, an Indiana corporation ("Miami"), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc., a North Carolina corporation ("PE-Carolinas"), Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation ("PE-Florida"), Progress Energy Service Company, LLC, a North Carolina limited liability company ("PESC"), and Duke Energy Business Services LLC, a Delaware limited liability company ("DEBS"), ~~on its own behalf and as successor in interest to Duke Energy Shared Services, Inc.~~ (DEBS and PESC are sometimes hereinafter referred to individually as a "Service Company" and collectively as the "Service Companiesy") (DE-Carolinas, DE-Ohio, DE-Indiana, DE-Kentucky, PE-Carolinas, PE-Florida, Progress Energy Service Company, and Miami are sometimes hereinafter referred to individually as a "Client Company" and collectively as the "Client Companies")~~, supersedes and restates in its entirety the Amended and Restated Service Company Utility Service Agreement entered into by the parties dated January 2, 2007~~~~September 1, 2008~~ ~~(the "Amended and Restated Service Agreement")~~. This Agreement supersedes and replaces in its entirely the Second Amended and Restated Utility Service Agreement dated September 1, 2008.

WITNESSETH

WHEREAS, ~~the terms of this Agreement are substantially similar to the Amended and Restated Service Agreement and the purpose of this Second~~

~~Amended and Restated Service Agreement is to clarify the parties' intentions regarding the scope of services. WHEREAS,~~ each of the Client Companies and each of the Service Companiesy is a subsidiary of Duke Energy Corporation;

WHEREAS, the Service Companiesy and the Client Companies have entered into this Agreement whereby the Service Companiesy agrees to provide and the Client Companies agree to accept and pay for various services as provided herein at cost, except to the extent otherwise required by Section 482 of the Internal Revenue Code; and

WHEREAS, economies and efficiencies benefiting the Client Companies will result from the performance by the Service Companiesy of services as herein provided;

NOW, THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Agreement covenant and agree as follows:

ARTICLE I – SERVICES

Section 1.1 The Service Companiesy shall furnish to the Client Companies, upon the terms and conditions hereinafter set forth, such of the services described in Appendix A hereto, at such times, for such periods and in such manner as the Client Companies may from time to time request and which the Service Company concludes it is equipped to perform. The Service Companiesy shall also provide Client Companies with such special services, including without limitation cost management services, in addition to those services described in Appendix A hereto, as may be requested by a Client Company and which the Service Company concludes it is equipped to perform. In supplying such services, the Service Companiesy may (i) arrange, where it deems appropriate, for the services of such experts, consultants, advisers and other persons with necessary qualifications as are required for or pertinent to the rendition of such services, and (ii) tender payments to third parties as agent for and on behalf of Client Companies, with such charges being passed through to the appropriate Client Companies.

Section 1.2 Each of the Client Companies shall take from the Service Companies~~y~~ such of the services described in Section 1.1 and such additional general or special services, whether or not now contemplated, as are requested from time to time by the Client Companies and which the Service Company concludes it is equipped to perform.

Section 1.3 The services described herein shall be directly assigned, distributed or allocated by activity, process, project, responsibility center, work order or other appropriate basis. A Client Company shall have the right from time to time to amend, alter or rescind any activity, process, project, responsibility center or work order, provided that (i) any such amendment or alteration which results in a material change in the scope of the services to be performed or equipment to be provided is agreed to by the Service Company, (ii) the cost for the services covered by the activity, process, project, responsibility center or work order shall include any expense incurred by the Service Company as a direct result of such amendment, alteration or rescission of the activity, process, project, responsibility center or work order, and (iii) no amendment, alteration or rescission of an activity, process, project, responsibility center or work order shall release a Client Company from liability for all costs already incurred by or contracted for by the Service Company pursuant to the activity, process, project, responsibility center or work order, regardless of whether the services associated with such costs have been completed.

Section 1.4 The Service Companies~~y~~ shall maintain a staff trained and experienced in the design, construction, operation, maintenance and management of public utility properties.

ARTICLE II - COMPENSATION

Section 2.1 Except to the extent otherwise required by Section 482 of the Internal Revenue Code, as compensation for the services to be rendered hereunder, each of the Client Companies shall pay to the Service Company all costs which reasonably can be identified and related to particular services performed by the Service Company for or on its behalf. Where more than one Client Company is involved in or has received benefits from a service performed, costs will be directly assigned, distributed or allocated, as set forth in Appendix A hereto, between or among such companies on a basis reasonably related to the service performed to the extent reasonably practicable.

Section 2.2 The method of assignment, distribution or allocation of costs described in Appendix A shall be subject to review annually, or more frequently if appropriate. Such method of assignment, distribution or allocation of costs may be modified or changed by the Service Companies~~y~~ without the necessity of an amendment to this Agreement, provided that in each instance, all services rendered hereunder shall be at actual cost thereof, fairly and equitably assigned, distributed or allocated, except to the extent otherwise required by Section 482 of the Internal Revenue Code. The Service Companies~~y~~ shall promptly advise the Client Companies and the North Carolina Utilities Commission ("NCUC"), the Public Service Commission of South Carolina ("PSCSC"), the Indiana Utility Regulatory Commission ("IURC"), The Public Utilities Commission of Ohio ("PUCO"), the Kentucky Public Service Commission ("KPSC;" and together with the NCUC, the PSCSC, the IURC and the PUCO, the "Affected State Commissions") from time to time of any material changes in such method of assignment, distribution or allocation. Such notice shall be in compliance with the requirements of applicable state law, regulations and regulatory conditions.

Section 2.3 The Service Companies~~y~~ shall render a monthly statement to each Client Company which shall reflect the billing information necessary to identify the costs charged for that month. By the last day of each month, each Client Company shall remit to ~~each~~the Service Company all charges billed to it. For avoidance of doubt, the Service Compan~~ies~~y and each Client Company may satisfy the foregoing requirement by recording billings and payments required hereunder in their common accounting systems without rendering paper or electronic monthly statements or remitting cash payments.

Section 2.4 Subject to Section 482 of the Internal Revenue Code, it is the intent of this Agreement that the payment for services rendered by the Service Compan~~ies~~y to the Client Companies shall cover all the costs of its doing business (less the cost of services provided to affiliated companies not a party to this Agreement and to other non-affiliated companies, and credits for any miscellaneous income items), including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, property insurance, injuries and damages, employee pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization and compensation for use of capital. Without limitation of the foregoing, "cost," as used in this Agreement, means fully embedded cost, namely, the sum of (1) direct costs, (2) indirect costs and (3) costs of capital.

ARTICLE III - TERM

Section 3.1 This Agreement is entered into as of the Effective Date and shall continue in force with respect to a Client Company until terminated by the Service Compan~~ies~~y and Client Company with respect to such Client Company (provided that no such termination with respect to less than all of the Client Companies shall thereby affect the term of this Agreement or any of the provisions hereof) or until terminated by unanimous agreement of all the parties then signatory to this Agreement.

ARTICLE IV – ACCOUNTS AND RECORDS

Section 4.1 The Service Companies~~y~~ shall utilize the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission.

Section 4.2 The Service Companies~~y~~ shall permit each Affected State Commission and applicable statutory utility consumer representative(s), together with other interested parties as required under applicable law, access to its accounts and records, including the basis and computation of allocations, necessary for each Affected State Commission to review a Client Company's operating results.

ARTICLE V – MISCELLANEOUS

Section 5.1 Counterparts. This Agreement may be executed in one or more counterparts, all of which shall be considered one and the same agreement and shall become effective when one or more counterparts have been signed by each party and delivered to the other parties.

Section 5.2 Entire Agreement; No Third Party Beneficiaries. This Agreement (including Appendix A and any other appendices or other exhibits or schedules hereto) (i) constitutes the entire agreement, and supersedes any prior agreements and understandings, both written and oral, among the parties with respect to the subject matter of this Agreement ~~(including without limitation the Amended and Restated Service Agreement~~; and (ii) is not intended to confer upon any person other than the parties hereto any rights or remedies.

Section 5.3 Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of New York, regardless of the laws that might otherwise govern under applicable principles of conflict of laws.

Section 5.4 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of each of the other parties. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 5.5 Amendments. This Agreement may not be amended except by an instrument in writing signed on behalf of each of the parties. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any Affected State Commission for its review or otherwise, each Client Company shall comply in all respects with any such requirements.

Section 5.6 Interpretation. When a reference is made in this Agreement to an Article, Section or Appendix or other Exhibit, such reference shall be to an Article or Section of, or an Appendix or other Exhibit to, this Agreement unless otherwise indicated. The headings contained in this Agreement are for convenience of reference only and shall not affect in any way the meaning or interpretation of this Agreement. Whenever the words "include", "includes" or "including" are used in this Agreement, they shall be deemed to be followed by the words "without limitation". The words "hereof", "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement. The definitions contained in this Agreement are applicable to the singular as well as the plural forms of such terms and to the masculine as well as to the feminine and neuter genders of such term. References to a person are also to its permitted successors and assigns.

Section 5.7 DE-Carolinas Conditions. In addition to the terms and conditions set forth herein, with respect to DE-Carolinas, the provisions set out in Appendix B are hereby incorporated herein by reference. In addition, DE-Carolinas' participation in this Agreement is explicitly subject to the Regulatory Conditions and Code of Conduct approved by the NCUC in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued March 24, 2006, in NCUC Docket No. E-7, Sub 795. In the event of any conflict between the provisions of this Agreement and the approved Regulatory Conditions and Code of Conduct provisions, the Regulatory Conditions and Code of Conduct shall govern.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the parties hereto have caused this ~~Second Amended and Restated~~ Service Agreement to be executed as of the date and year first above written.

DUKE ENERGY BUSINESS SERVICES LLC

By: ______________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY CAROLINAS, LLC

By: ______________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY OHIO, INC.

By: ______________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY INDIANA, INC.

By: ______________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY KENTUCKY, INC.

By: ______________________
Richard G. Beach
Assistant Secretary

MIAMI POWER CORPORATION

By____________________
Richard G. Beach
Assistant Secretary

CAROLINA POWER & LIGHT COMPANY d/b/a
PROGRESS ENERGY CAROLINAS, INC.

By____________________

FLORIDA POWER CORPORATION d/b/a
PROGRESS ENERGY FLORIDA, INC.

By____________________

PROGRESS ENERGY SERVICE COMPANY, LLC

By____________________

APPENDIX A

Description of Services and Determination
<u>of Charges for Services</u>

I. The Service Compan~~ies~~y will maintain an accounting system for accumulating all costs on an activity, process, project, responsibility center, work order, or other appropriate basis. To the extent practicable, time records of hours worked by Service Company employees will be kept by activity, process, project, responsibility center or work order. Charges for salaries will be determined from such time records and will be computed on the basis of employees' labor costs, including the cost of fringe benefits, indirect labor costs and payroll taxes. Records of employee-related expenses and other indirect costs will be maintained for each functional group within the Service Company (hereinafter referred to as "Function"). Where identifiable to a particular activity, process, project, responsibility center or work order, such indirect costs will be directly assigned to such activity, process, project, responsibility center or work order. Where not identifiable to a particular activity, process, project, responsibility center or work order, such indirect costs within a Function will be distributed in relationship to the directly assigned costs of the Function. For purposes of this Appendix A, any costs not directly assigned or distributed by the Service Company will be allocated monthly.

II. Service Company costs accumulated for each activity, process, project, responsibility center or work order will be directly assigned, distributed, or allocated to the Client Companies or other Functions within the Service Company as follows:

1. Costs accumulated in an activity, process, project, responsibility center or work order for services specifically performed for a single Client Company or Function will be directly assigned and charged to such Client Company or Function.

2. Costs accumulated in an activity, process, project, responsibility center or work order for services specifically performed for two or more Client Companies or Functions will be distributed among and charged to such Client Companies or Functions. The appropriate method of distribution will be determined by the Service Company on a case-by-case basis consistent with the nature of the work performed and will be based on the application of one or more of the methods described in paragraphs IV and V of this

Appendix A. The distribution method will be provided to each such affected Client Company or Function.

3. Costs accumulated in an activity, process, project, responsibility center or work order for services of a general nature which are applicable to all Client Companies or Functions or to a class or classes of Client Companies or Functions will be allocated among and charged to such Client Companies or Functions by application of one or more of the methods described in paragraphs IV and V of this Appendix A.

III. For purposes of this Appendix A, the following definitions or methodologies shall be utilized:

1. Where applicable, the following will be utilized to convert gas sales to equivalent electric sales: 1 cubic foot of gas sales equals 0.303048 kilowatt-hour of electric sales (based on electricity at 3412 Btu/kWh and natural gas at 1034 Btu/cubic foot).

2. "Domestic utility" refers to a utility which operates in the contiguous United States of America.

3. "Gross margin" refers to revenues as defined by Generally Accepted Accounting Principles, less cost of sales, including but not limited to fuel, purchased power, emission allowances and other cost of sales.

4. "Distribution" means electric distribution and local gas distribution as applicable.

5. "Distribution Lines" mean electric power lines at distribution voltages measured in circuit miles, and gas mains and lines, as applicable.

The weights utilized in the weighted average ratios in paragraph V of this Appendix A shall represent the percentage relationship of the activities associated with the function for which costs are to be allocated. For example, if an expense item is to be allocated on the weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the Total Property, Plant and Equipment ("PP&E") Ratio, and the activity to be allocated is one-third gross margin related, one-third labor related and one-third PP&E related, 33 percent of the Gross Margin Ratio would be utilized, 33 percent of the Labor Dollars Ratio and 34 percent of the PP&E Ratio would be utilized. To illustrate this application, assuming that the Gross Margin Ratio were 53.75 percent for Company A and 46.25 percent for Company B, the Labor Dollars Ratio were 25 percent for Company A and 75 percent for Company B, and the Total PP&E Ratio were 60 percent for Company A and 40 percent for Company B, the following weighted average ratio would be computed:

		Company A		Company B	
Activity	Weight	Ratio	Weighted	Ratio	Weighted
Gross Margin Ratio	33%	53.75%	17.74%	46.25%	15.26%
Labor Dollars Ratio	33%	25.00%	8.25%	75.00%	24.75%
Total Property, Plant and Equipment Ratio	34%	60.00%	20.40%	40.00%	13.60%
	100%		46.39%		53.61%

IV. The following allocation methods will be applied, as specified in paragraph V of this Appendix A, to assign costs for services applicable to two or more clients and/or to allocate costs for services of a general nature.

1. Sales Ratio

   A ratio, based on the applicable domestic firm kilowatt-hour electric sales (and/or the equivalent cubic feet of gas sales, where applicable), excluding intra-system sales, for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable), This ratio will be determined annually, or at such time as may be required due to a significant change.

2. Electric Peak Load Ratio

   A ratio, based on the sum of the applicable monthly domestic firm electric maximum system demands for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually, or at such time as may be required due to a significant change.

3. Number of Customers Ratio

A ratio, based on the sum of the applicable domestic firm electric customers (and/or gas customers, where applicable) at the end of a recent month in the preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually, or at such time as may be required due to a significant change.

4. Number of Employees Ratio

A ratio, based on the applicable number of employees at the end of a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually, or at such time as may be required due to a significant change.

5. Construction-Expenditures Ratio

A ratio, based on the applicable projected construction expenditures for the following twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). Separate ratios will be computed for total construction expenditures and appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually, or at such time as may be required due to a significant change.

6. Miles of Distribution Lines Ratio

In the case of electric Distribution, a ratio, based on the applicable installed circuit miles of domestic electric Distribution Lines, and in the case of gas Distribution, a ratio, based on the applicable installed miles of domestic gas Distribution Lines, in either case at the end of the preceding calendar year, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies. This ratio will be determined annually, or at such time as may be required due to a significant change.

7. Circuit Miles of Electric Transmission Lines Ratio

A ratio, based on the applicable installed circuit miles of domestic electric transmission lines at the end of the preceding calendar year, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies. This ratio will be determined annually, or at such time as may be required due to a significant change.

8. Number of Central Processing Unit Seconds Ratio

A ratio, based on the sum of the applicable number of central processing unit seconds expended to execute mainframe computer software applications for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company or Service Company Function, and the denominator of which is for all Client Companies, (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually, or at such time as may be required due to a significant change.

9. Revenues Ratio

A ratio, based on the total applicable revenues for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

10. Inventory Ratio

A ratio, based on the total applicable inventory balance for the preceding year, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). Separate ratios will be computed for total inventory and the appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually or at such time as may be required due to a significant change.

11. Procurement Spending Ratio

A ratio, based on the total amount of applicable procurement spending for the preceding year, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. Separate ratios will be computed for total procurement spending and appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually or at such time as may be required due to a significant change.

12. Square Footage Ratio

A ratio, based on the total amount of applicable square footage occupied in a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

13. Gross Margin Ratio

A ratio, based on the total applicable gross margin for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

14. Labor Dollars Ratio

A ratio, based on the total applicable labor dollars for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

15. Number of Personal Computer Work Stations Ratio

A ratio, based on the total number of applicable personal computer work stations at the end of a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

16. Number of Information Systems Servers Ratio

A ratio, based on the total number of applicable servers at the end of a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

17. Total Property, Plant and Equipment Ratio

A ratio, based on the total applicable Property, Plant and Equipment balance (net of accumulated depreciation and amortization) for the preceding year, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

18. Generating Unit MW Capability Ratio

A ratio, based on the total applicable installed megawatt capability for the preceding year, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

19. Number of Meters Ratio

A ratio, based on the number of electric and/or gas meters, as applicable, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies. Separate ratios will be computed for appropriate meter classifications (e.g., type of metering technology). This ratio will be determined annually, or at such time as may be required due to a significant change.

20. O&M Expenditures Ratio

A ratio, based on the operation and maintenance (O&M) expenditures for a prior twelve month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy ~~Corporation's non-utility and non-domestic utility affiliates, where~~ applicable). Separate ratios will be computed for total O&M expenditures and appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually.

V. A description of each Function's activities, which may be modified from time to time by the Service Companies~~y~~, is set forth below in paragraph "a" under each Function. As described in paragraph II, "1" and "2" of this Appendix A, where identifiable, costs will be directly assigned or distributed to Client Companies or to other Functions of the Service Company. For costs accumulated in activities, processes, projects, responsibility centers, or work orders which are for services of a general nature that cannot be directly assigned or distributed, as described in paragraph II, "3" of this Appendix A, the method or methods of allocation are set forth below in paragraph "b" under each Function. For any of the functions set forth below other than Information Systems, Transportation, Human Resources or Facilities, costs of a general nature to be allocated pursuant to this Agreement shall exclude costs of a general nature which have been allocated to affiliated companies not a party to this Agreement. Substitution or changes may be made in the methods of allocation hereinafter specified, as may be appropriate, and will be provided to state regulatory agencies and to each Client Company. Any such substitution or changes shall be in compliance with the requirements of applicable state law, regulations and regulatory conditions.

1. Information Systems

a. Description of Function

Provides communications and electronic data processing services. The activities of the Function include:

(1) Development and support of mainframe computer software applications.

(2) Procurement and support of personal computers and related network and software applications.

(3) Development and support of distributed computer software applications (e.g., servers).

(4) Installation and operation of communications systems.

(5) Information systems management and support services.

b. Method of Allocation

(1) Development and support of mainframe computer software applications - allocated between the Client Companies and other Functions of the Service Company based on the number of Central Processing Unit Seconds Ratio, or allocated among the Client Companies on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio as appropriate.

(2) Procurement and support of personal computers and related network and software applications - allocated to the Client Companies and to other Functions of the Service Company based on the Number of Personal Computer Work Stations Ratio.

(3) Development and support of distributed computer software applications - allocated to the Client Companies and to other Functions of the Service Company based on the Number of Information Systems Servers Ratio.

(4) Installation and operation of communications systems - allocated to the Client Companies and to other Functions of the Service Company based on the Number of Employees Ratio.

(5) Information systems management and support services – allocated to the Client Companies and to other Functions of the Service Company based

on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

2. Meters
   a. Description of Function
      Procures, tests and maintains meters.
   b. Method of Allocation
      Allocated to the Client Companies based on the Number of Customers Ratio.

3. Transportation
   a. Description of Function
      (1) Procures and maintains vehicles and equipment.
      (2) Procures and maintains aircraft and equipment.
   b. Method of Allocation
      (1) The costs of maintaining vehicles and equipment are allocated to the Client Companies and to other Functions of the Service Company based on the Number of Employees Ratio.
      (2) The costs of maintaining aircraft and equipment are allocated to the Client Companies and to other Functions of the Service Company based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

4. System Maintenance
   a. Description of Function
      Coordinates maintenance and support of electric transmission systems and Distribution systems.
   b. Method of Allocation
      (1) Services related to electric transmission systems - allocated to the Client Companies based on the Circuit Miles of Electric Transmission Lines Ratio.

(2) Services related to electric Distribution systems - allocated to the Client Companies based on the Miles of Distribution Lines Ratio.

(3) Services related to gas Distribution systems – allocated to the Client Companies based on the Labor Dollars Ratio.

5. Marketing and Customer Relations

a. Description of Function

~~Advises the Client Companies in relations with domestic utility customers.~~

The activities of the Function include:

(1) Design and administration of sales and demand-side management programs.

(2) Customer meter reading, billing and payment processing.

(3) Customer services including the operation of call center.

b. Method of Allocation

(1) Design and administration of sales and demand-side management programs - allocated to the Client Companies based on the Sales Ratio.

(2) Customer billing and payment processing - allocated to the Client Companies based on the Number of Customers Ratio.

(3) Customer Services - allocated to the Client Companies based on the Number of Customers Ratio.

6. Transmission and Distribution Engineering and Construction

a. Description of Function

Designs and monitors construction of electric transmission and Distribution Lines and associated facilities. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.

b. Method of Allocation

(1) Transmission engineering and construction allocated to the Client Companies based on the Electric Transmission Plant's Construction-Expenditures Ratio.

(2) Distribution engineering and construction allocated to the Client Companies based on the Distribution plant's Construction-Expenditures Ratio.

7. Power Engineering and Construction

a. Description of Function

Designs, monitors and supports the construction and retirement of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units, improvements to existing electric generating units, and the retirement of existing electric generating equipment, including developing associated operating processes with operations personnel. Prepares cost and schedule estimates and visits construction sites to ensure that construction and retirement activities meet schedules and plans..

b. Method of Allocation

Allocated to the Client Companies based on the Electric Production Plant's Construction-Expenditures Ratio.

8. Human Resources

a. Description of Function

Establishes and administers policies and supervises compliance with legal requirements in the areas of employment, compensation, benefits and employee health and safety. Processes payroll and employee benefit payments. Supervises contract negotiations and relations with labor unions.

b. Method of Allocation

Allocated to the Client Companies and to other Functions of the Service Company based on the Number of Employees Ratio.

9. Materials Management

a. Description of Function

Provides services in connection with the procurement of materials and contract services, processes payments to vendors, and provides management of material and supplies inventories.

b. Method of Allocation

(1) Procurement of materials and contract services and vendor payment processing - allocated to the Client Companies and to other Functions of the Service Company based on the Procurement Spending Ratio.

(2) Management of materials and supplies inventory – allocated to the Client Companies on the Inventory Ratio.

10. <u>Facilities</u>

a. Description of Function

Operates and maintains office and service buildings. Provides security and housekeeping services for such buildings and procures office furniture and equipment.

b. Method of Allocation

Allocated to the Client Companies and to other Functions of the Service Company based on the Square Footage Ratio.

11. <u>Accounting</u>

a. Description of Function

Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

12. <u>Power and Gas Planning and Operations</u>

a. Description of Function

Coordinate the planning, management and operation of Duke Energy Corporation's power generation, transmission and Distribution systems. The activities of the Function include:

(1) System Planning - planning of additions and retirements to the electric generation units and transmission and Distribution systems belonging to the regulated utilities owned by Duke Energy Corporation.

(2) System Operations - coordination of the dispatch and operation of the electric generating units and transmission and Distribution systems belonging to the regulated utilities owned by Duke Energy Corporation.

(3) Power Operations – provides management and support services for the electric generation units owned or operated by subsidiaries of Duke Energy Corporation.

(4) Wholesale Power Operations – coordination of Duke Energy Corporation's wholesale power operations.

b. Method of Allocation

(1) System Planning

(a) Generation planning - allocated to the Client Companies based on the Electric Peak Load Ratio.

(b) Transmission planning – allocated to the Client Companies based on the Electric Peak Load Ratio.

(c) Electric Distribution planning - allocated to the Client Companies based on a weighted average of the Miles of Distribution Lines Ratio and the Electric Peak Load Ratio.

(d) Gas Distribution planning – allocated to the Client Companies based on the Construction-Expenditures Ratio.

(2) System Operations –

(a) Generation Dispatch - allocated to the Client Companies based on the Sales Ratio.

(b) Transmission Operations - allocated to the Client Companies based on a weighted average of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio.

(c) Electric Distribution Operations - allocated to the Client Companies based on a weighted average of the Miles of Distribution Lines Ratio and the Electric Peak Load Ratio.

(d) Gas Distribution Operations – allocated to the Client Companies based on the Construction-Expenditures Ratio.

(3) Power Operations – allocated to the Client Companies based on the Generating Unit MW Capability Ratio.

(4) Wholesale Power Operations – allocated to the Client Companies based on the Sales Ratio.

13. Public Affairs

a. Description of Function

Prepares and disseminates information to employees, customers, government officials, communities and the media. Provides graphics, reproduction lithography, photography and video services.

b. Method of Allocation

(1) Services related to corporate governance, public policy, management and support services - allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

(2) Services related to utility specific activities - allocated to the Client Companies based on a weighted average of the Number of Customers Ratio and the Number of Employees Ratio.

14. Legal

a. Description of Function

Renders services relating to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

15. Rates

a. Description of Function

Determines the Client Companies' revenue requirements and rates to electric and gas requirements customers. Administers interconnection and joint ownership agreements. Researches and forecasts customers' usage.

b. Method of Allocation

Allocated to the Client Companies based on the Sales Ratio.

16. Finance

a. Description of Function

Renders services to Client Companies with respect to investments, financing, cash management, risk management, claims and fire prevention. Prepares budgets, financial forecasts and economic analyses.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

17. Rights of Way

a. Description of Function

Purchases, surveys, records, and sells real estate interests for Client Companies.

b. Method of Allocation

(1) Services related to Distribution system - allocated to the Client Companies based on the Miles of Distribution Lines Ratio.

(2) Services related to electric generation system- allocated to the Client Companies based on the Electric Peak Load Ratio.

(3) Services related to electric transmission system – allocated to the Client Companies based on the Circuit Miles of Electric Transmission Lines Ratio.

18. Internal Auditing

a. Description of Function

Reviews internal controls and procedures to ensure that assets are safeguarded and that transactions are properly authorized and recorded.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

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19. Environmental, Health and Safety

a. Description of Function

Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.

b. Method of Allocation

(1) Services related to corporate governance, environmental policy, management and support services - allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

(2) Services related to utility specific activities -- allocated to the Client Companies based on the Sales Ratio

20. Fuels

a. Description of Function

Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.

b. Method of Allocation

Allocated to the Client Companies based on the Sales Ratio.

21. Investor Relations

a. Description of Function

Provides communications to investors and the financial community, performs transfer agent and shareholder record keeping functions, administers stock plans and performs stock-related regulatory reporting.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

22. Planning

a. Description of Function

Facilitates preparation of strategic and operating plans, monitors trends and evaluates business opportunities.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

23. Executive

a. Description of Function

Provides general administrative and executive management services.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

APPENDIX B

DE-CAROLINAS CONDITIONS

1. In connection with the NCUC approval the Merger in NCUC Docket No. E-7, Sub 795, the NCUC adopted certain Regulatory Conditions and a revised Code of Conduct governing transactions between DE-Carolinas and its affiliates. Pursuant to the Regulatory Conditions, the following provisions are applicable to DE-Carolinas:

(a) DE-Carolinas' participation in this Agreement is voluntary. DE-Carolinas is not obligated to take or provide services or make any purchases or sales pursuant to this Agreement, and DE-Carolinas may elect to discontinue its participation in this Agreement at its election after giving notice under Section 3.1 of the Agreement.

(b) DE-Carolinas may not make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder.

(c) DE-Carolinas may not seek to reflect in rates any (i) costs incurred under this Agreement exceeding the amount allowed by the NCUC or (ii) revenue level earned under this Agreement less than the amount imputed by the NCUC; and

(d) Except to the extent that requesting FERC review and authorization pursuant to Section 1275(b) of Subtitle F in Title XII of PUHCA 2005, as provided in Regulatory Condition No. 21, may be determined to have preemptive effect under the law, DE-Carolinas will not assert in any forum that the NCUC's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is preempted and will bear the full risk of any preemptive effects of federal law with respect to this Agreement.

2. With respect to the transfer by DE-Carolinas under this Agreement of the control of, operational responsibility for, or ownership of any DE-Carolinas assets used for the generation, transmission or distribution of electric power to its North Carolina retail customers with a gross book value in excess of ten million dollars ($10 million), the following shall apply:

(a) DE-Carolinas may not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations and orders of the NCUC promulgated thereunder; and

(b) DE-Carolinas may not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 28, 2011

STAFF-DR-01-008

REQUEST:

Provide the Duke Energy and Progress annual reports to shareholders and audited financial statements, including notes to the financial statements, for the years 2006 through 2008.

RESPONSE:

a. Please see Attachment Staff-DR-01-008 (a) – (c) for Duke Energy annual reports.

b. Please see Attachment Staff DR-01-008(i)-(iii) for Progress Energy annual reports.

PERSON RESPONSIBLE: a. James E. Rogers (Duke)

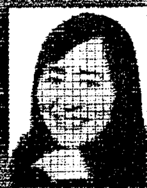
b. William D. Johnson (Progress)

Duke Energy®

Changing minds. Changing habits.

2006 SUMMARY ANNUAL REPORT

IN THIS REPORT



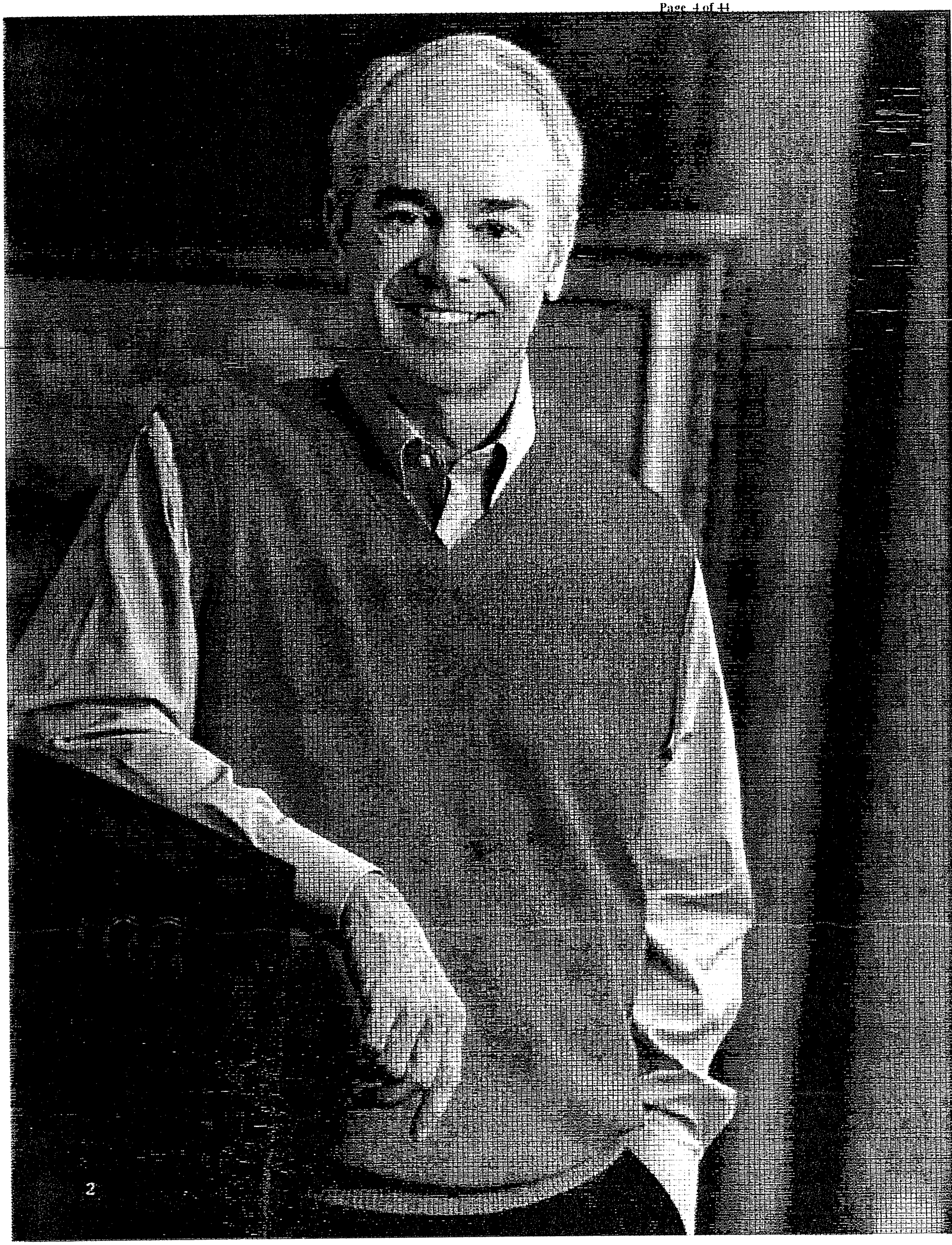
ABOUT THE COVER

… to solve the new energy equation.

We face a new energy equation with many variables. Increasing demand for energy is a key driver of rising energy prices. As a result, there is a renewed focus on renewable energy and energy efficiency — "save-a-watts" vs. megawatts. There is mounting concern about global climate change and further reducing air emissions. And, we must continue to grow earnings and dividends.

These variables present both challenges and opportunities. We believe we can solve this new equation with our sustainability focus. This means working to balance the needs of all of our stakeholders. These efforts will keep our prices affordable and our service reliable as we continue to work to reduce our environmental footprint and earn superior returns.

This delicate balancing act requires us to challenge conventional wisdom with new thinking and innovation. It means changing our own minds and habits and those of our stakeholders. We must still generate megawatts, but we believe we can produce significant save-a-watts as well. In 2006, we repositioned Duke Energy to do just that. Read on …



Dear fellow investors, customers, employees and all who have a vested interest in our success — our partners, suppliers, policymakers, regulators and communities:

I want to thank the entire Duke Energy team for accomplishing both a merger and a spinoff last year. Never before in my career have I seen people work so hard to resolve so many complex issues. Our many financial, operational and policy accomplishments in 2006 were the result of your dedication and support.

For our other stakeholders, let me summarize our key accomplishments simply by saying that we did what we said we would do in our 2006 Charter.

2006 ongoing diluted earnings per share of $1.81 exceeded 2005 ongoing diluted earnings per share of $1.73. Duke Energy's total shareholder return for 2006, before the spinoff of Spectra Energy in early 2007, was 26.3 percent. We outperformed both the Philadelphia Stock Exchange Utility Sector Index (20 percent) and the S&P 500 Index (15.8 percent).

The strategic steps we took last year positioned the company for growth in 2007 and beyond. We established an industry-leading electric power platform through the successful execution of the merger with Cinergy — and we did it in 11 months.

(LEFT) JAMES E. ROGERS, CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER

Looking back. Looking forward.

2006 was a transformational year for Duke Energy. By taking decisive actions, we lowered our risk profile and repositioned the company. As a leading pure-play electric company with a strong balance sheet, we are in a favorable position to achieve our 2007 goals, which will drive earnings and dividend growth over the long term.

2006 Major Achievements

- ✔ Merged with Cinergy to increase the scale and scope of our power business.
- ✔ Reduced our risk profile by selling our unregulated power plants outside the Midwest and by selling our Commercial Marketing and Trading business.
- ✔ Formed a joint venture with Morgan Stanley Real Estate Fund for Crescent Resources.
- ✔ Repurchased $500 million of stock.
- ✔ Acquired, filed for certificate, or announced our intent to build new generation assets throughout our five states. We estimate that we will need to increase our generating capacity by approximately 6,400 megawatts over the next 10 years.
- ✔ Announced numerous expansions of our gas transmission system.
- ✔ Achieved our 2006 employee incentive target.
- ✔ Spun off Spectra Energy on Jan. 2, 2007.

Goals for 2007*

- Establish the identity and culture of the new Duke Energy, unifying our people, values, strategy, processes and systems.
- Optimize our operations by focusing on safety, simplicity, accountability, inclusion, customer satisfaction, cost management and employee development.
- Achieve public policy, regulatory and legislative outcomes that balance our customers' needs for reliable energy at competitive prices with our shareholders' expectation of superior returns.
- Invest in energy infrastructure that meets rising customer demands for reliable energy in an efficient and environmentally sound manner.
- Achieve 2007 financial objectives and position the company to meet future growth targets.

*See the 2007 Duke Energy Charter on page 9.

We reduced our earnings volatility and business risk by selling our commercial marketing and trading operations, and effectively half of our real estate development company, Crescent Resources. These transactions raised almost $2 billion in after-tax cash, most of which will be invested in our lower-risk, energy infrastructure businesses

In customer satisfaction, we have consistently ranked in the top quartile in several independent utility studies. Last year, our utility companies in the South and Midwest finished in the top 10 nationally in the Key Account Benchmark Study. In addition, we ranked first in the South and best in the nation among small and mid-sized business customers, according to J.D. Power and Associates.

We provided leadership on industry issues. I currently serve as chairman of Edison Electric Institute and I co-chair the National Action Plan on Energy Efficiency and the Alliance to Save Energy. Other members of the Duke Energy leadership team also help to shape the state and federal policy decisions that affect our business.

We continued to build a high-performance, sustainability-focused culture characterized by diversity, inclusion, employee development and leadership. And we established new safety incentives for 2007 to reinforce our concern for each other and our customers.

SO WHY DID WE CHOOSE TO GET LARGER AND THEN GET SMALLER?

Very simply, scale and focus

Our merger with Cinergy in April 2006 gave our electric business the scale it needed to stand alone. To unlock even greater value, three months later we announced that we would separate our natural gas business and our electric business into two strong pure-play companies: Spectra Energy for gas and Duke Energy for electric power. We completed the spinoff of Spectra Energy in January 2007. Today Duke Energy is one of the top five electric companies in the United States in market capitalization.

Having the strategic focus of a pure-play electric company will help us meet the challenges and seize the opportunities to solve what we call the new energy equation

In this equation, we must meet our customers' needs for affordable and reliable electric power while meeting more stringent environmental rules that will inevitably increase costs.

We must raise capital for long-term investments in more environmentally friendly generation capacity, renewable energy and energy efficiency. And we must reassure investors who may be wary of long-term capital construction programs.

Balancing these factors and solving the new energy equation will require a new approach to utility regulation. It will require us to change minds and change habits. It will require us to see and understand the goals of each of our stakeholder groups. This letter and the rest of this report will detail our plans to do that.

WHAT INVESTORS CAN EXPECT IN 2007 AND BEYOND

Our strategy to increase earnings and dividends in the long term is straightforward:

- Steadily improve our sales growth
- Earn solid returns on our significant capital investments, and
- Continue achieving additional cost reductions from the merger and from our continuous improvement efforts.

These three drivers — sales, investments and cost savings — are essential to achieving both our 2007 financial objectives and long-term growth.

You can read all of our 2007 objectives in our Charter on page 9. Our 2007 employee incentive target of $1.15 per share is based on ongoing diluted earnings. The $1.15 serves as the basis for 4 to 6 percent annual earnings growth through the end of 2009. We expect dividend growth to be in line with earnings growth.

Our business plan projects a quarterly dividend increase of $0.01 beginning in the third quarter of 2007. This dividend increase — to be decided by the board of directors — would be in line with our expectation to increase dividends consistent with a 70 to 75 percent payout target.

SOLVING THE NEW ENERGY EQUATION: CHANGING MINDS AND CHANGING HABITS

Our actions in 2006 put us in a strong position to grow as we address the variables of the new energy equation:

- Building new power plants to meet steadily increasing demand
- Using a diverse mix of fuels and technologies at our new plants to limit our future price, reliability and environmental risks
- Deploying new technologies to modernize our transmission and distribution grids to boost efficiency and reliability, and to support new energy efficiency initiatives
- Obtaining legislation and regulatory treatment that will let us recover our financing costs as we build new and more efficient power plants (megawatts) and as we promote energy efficiency ("save-a-watts") with new initiatives on both sides of the meter
- Realizing the efficiencies and cost savings from the merger while maintaining our operational excellence, and
- Shaping new federal rules that limit carbon emissions to ensure our customers and other stakeholders are fairly treated

We will solve the new energy equation by challenging conventional wisdom. We will invest in new technology. We will balance the variables by working collaboratively with all stakeholders to find the best and fairest solutions.

Let me briefly highlight each variable and spell out our strategy for addressing it. This will also give you a good overview of our near-term and long-term growth strategies.

Building new power plants to meet steadily increasing demand. In the Carolinas, we are adding between 40,000 and 60,000 new customers annually. In Indiana, Kentucky and Ohio, we are adding 11,000 to 16,000 new customers each year. For the next three years, we expect annual kilowatt-hour sales growth of about 1.5 percent in the Carolinas and about 1 percent in the Midwest.

We are required by law to meet the electric power needs of our customers as economically and reliably as possible. Each year, we perform an extensive analysis to update our forecasts for customer power demand and study all viable and economical options to meet that demand. In the past, we have been successful in meeting our customer growth by operating our power plants efficiently, by purchasing peaking power plants and by buying power on the wholesale market as needed.

Today's growth projections suggest that we will need to increase our generating capacity by approximately 6,400 megawatts over the next 10 years. Most of this new capacity will be in the Carolinas, and the remainder in Indiana.

Even now, we need nearly 1,500 megawatts of new generation in Ohio to meet existing demand. We plan to build or buy new generation there if the state enacts legislation that will allow utilities to own generation facilities.

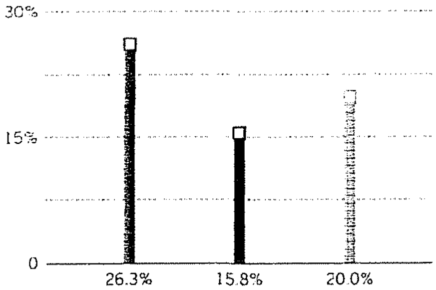
Our newest base load plants — those designed to operate around the clock — were completed in 1986 in the Carolinas and in 1991 in the Midwest. It takes six to 10 years to plan, permit and construct such plants. We are seeking permits now for plants that we'll need in 2011, when we expect to have more than 250,000 additional customers.

We anticipate annual capital expenditures of approximately $3.5 billion from 2007 through 2009 for expansion of our generation capacity, environmental retrofits, nuclear fuel, maintenance and other expenses. Included in this amount is expansion capital for:

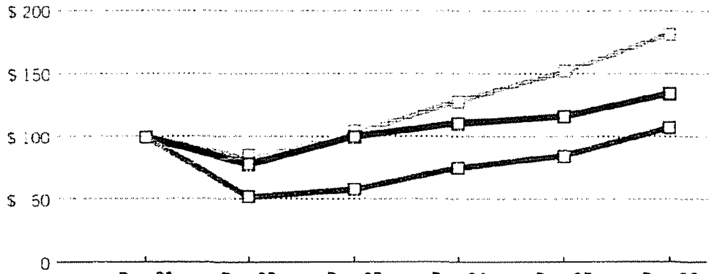
- Expanding generation in North Carolina
- Planning a new cleaner-coal integrated gasification combined cycle (IGCC) plant in Indiana, and
- Exploring the development of a new nuclear plant in South Carolina.

We expect that new generation and other infrastructure investments over the next three years will increase the total rate base in our five states by about 25 percent from the current $16 billion to $20 billion (less depreciation and amortization). The returns generated from a growing rate base will ultimately translate into long-term earnings growth — and we expect our rates to remain below the national average.

COMPARISON OF 2006 TOTAL RETURN



COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN



	Dec. 01	Dec. 02	Dec. 03	Dec. 04	Dec. 05	Dec. 06
☐	$ 100	$ 51.80	$ 57.98	$ 75.50	$ 85.39	$ 107.81
☐	$ 100	$ 77.90	$ 100.25	$ 111.15	$ 116.61	$ 135.02
☐	$ 100	$ 81.65	$ 101.95	$ 128.57	$ 151.99	$ 182.44

Assumes $100 was invested on December 31, 2001 in company common stock and each index. Values are as of December 31 assuming dividends are reinvested.

LEGEND

- ☐ Duke Energy Corporation
- ☐ S&P 500 Index
- ☐ Philadelphia Stock Exchange Utility Sector Index

OVER A FIVE-YEAR PERIOD BEGINNING DECEMBER 31, 2001, DUKE ENERGY'S TOTAL SHAREHOLDER RETURN (TSR) HAS LAGGED BOTH THE S&P 500 INDEX AND THE PHILADELPHIA STOCK EXCHANGE UTILITY INDEX. BUT, IN 2006, INVESTORS RESPONDED FAVORABLY TO THE DECISIVE ACTIONS WE TOOK TO LOWER OUR RISK PROFILE AND REPOSITION DUKE ENERGY AS A LEADING PURE-PLAY ELECTRIC COMPANY. DUKE ENERGY'S TSR FOR 2006 (PRE-SPINOFF OF SPECTRA ENERGY) WAS 26.3 PERCENT, WHICH EXCEEDED THE PHILADELPHIA STOCK EXCHANGE UTILITY SECTOR INDEX (20 PERCENT) AND THE S&P 500 INDEX (15.8 PERCENT).

Using a diverse mix of fuels and technologies at our new plants to limit our future price, reliability and environmental risks. One of the reasons our average price for electricity is below the national average is that 98 percent of our energy is generated from coal and nuclear power.

For our Cliffside Station, we proposed building two new 800-megawatt units using supercritical coal technology. This is the most environmentally efficient pulverized coal technology available today. Because of their increased efficiencies, these plants typically burn 10 percent less coal than conventional units and emit significantly less sulfur dioxide and nitrogen oxide.

As I was finishing this letter, we received a notice of decision from the North Carolina Utilities Commission (NCUC), which authorized building one of the two units. The commission also accepted our commitment to invest 1 percent of our revenues in the Carolinas for energy efficiency, subject to appropriate regulatory treatment, and our plan to retire older, less efficient units.

Our cost estimates were based on two units, and we still need an air permit for this project. So as you read this, we are studying the Cliffside project to determine how to proceed. We won't make a decision until we have a clearer understanding of the overall costs as well as the conditions of the air permit. We are also evaluating the possibility of enhancing and accelerating natural gas-fired plants in our portfolio.

In Indiana, we continue to explore development of a new 630-megawatt IGCC plant. IGCC technology is less proven, but has the potential to significantly reduce emissions. Additionally, the geology of the plant location is conducive to underground storage of captured carbon emissions. We believe that investing in this next generation of coal-plant technology is an important part of meeting our environmental commitments.

Because the Cliffside and IGCC projects use more environmentally friendly technologies, they were authorized for significant federal tax credits by the U.S. Department of Energy upon their completion. This is further evidence that Duke Energy is on the forefront of new cleaner coal technology.

We are also proposing to build a new nuclear plant in South Carolina. New nuclear plants will encounter challenges, including used fuel storage, cost recovery and a new licensing process. But nuclear energy has one big advantage: It produces no greenhouse gas emissions, and we believe that will help offset the other challenges.

Deploying new technologies to modernize our transmission and distribution grids to boost efficiency and reliability, and to support new energy efficiency initiatives. Complementing our capital investments in new generation is our renewed commitment to energy efficiency. Our job is to educate and support our customers — to change minds and habits — to help them better manage their energy use to reduce both peak and overall demand.

Energy efficiency can be measured in save-a-watts, the *number of megawatts we don't need to supply* when customers are being smart about their energy consumption. Efficient energy practices are just as important as coal, nuclear, natural gas and renewable energy. That's why we think of efficiency as the "fifth fuel."

With our strong customer relationships and back office systems, we are well positioned to make energy efficiency a significant part of our portfolio. Duke Energy has appointed a vice president of energy efficiency, a chief technology officer and a vice president of regulatory strategy. *You will meet them in the pages that follow.* We believe that their focused approach will make energy efficiency a new asset for all of our stakeholders, especially our customers and investors.

Energy efficiency is the core of our commitment to building a sustainable business model. We intend to manage financial, environmental and social opportunities and risks effectively, so we'll still be doing business many years from now.

You can be part of our commitment to sustainability leadership, too. We are again offering to make a $1 donation to The Nature Conservancy for every shareholder who signs up for electronic delivery of our annual report, proxy statement and our other financial information. Currently, more than 80,000 of you have chosen electronic delivery, and we intend to make an equivalent donation in dollars to The Nature Conservancy. Electronic delivery helps us in two ways: It preserves our natural resources, and it significantly *reduces our printing and mailing costs.* You need to sign up only once, and you can do so at this Web link: https://www.icsdelivery.com/duk/index.html.

Obtaining legislation and regulatory treatment that will let us recover our financing costs as we build new and more efficient power plants (megawatts) and as we promote energy efficiency (save-a-watts) with new initiatives on both sides of the meter. We are working this year to create a regulatory framework that balances the needs of our customers, our investors and our environment. Allowing us to recover financing costs as we incur them would lower the overall cost of projects as well as allow us to spread out rate increases over the course of the building cycle, avoiding large one-time increases.

We are pursuing such legislation in the Carolinas that would cover both the Cliffside station in North Carolina and a proposed new nuclear station in South Carolina. We are also seeking to recover our upfront development costs for the nuclear plant. We have been clear that we will not move forward with a nuclear plant unless we know that we can recover our financing costs in rates as we build.

In Ohio, we are pursuing a two-part regulatory strategy: First, we filed a request to extend the Rate Stabilization Plan through 2010. Second, we are also promoting legislation that would allow a regulated distribution company the *choice of whether to build or to purchase new generation.*

Success on this front depends on our ability to change minds. We need to persuade legislators and regulators to *give energy efficiency investments the same weight as* new generation investments. Conventional wisdom says that regulators reward us for selling more of our product, not less. We want to change the paradigm, by persuading them that utilities should be rewarded for energy efficiency as well as sales. If we can earn almost as much for saving a watt as for making a watt, everyone will benefit. With *this kind of economic impartiality, we can provide reliable* service, conserve precious resources and reduce emissions while still delivering a fair return to our investors.

We believe we can succeed with our regulatory agenda. We are seeking a consensus on policies that balance the needs of all of our stakeholders. This collaborative approach has produced constructive regulatory outcomes for our stakeholders before

2007 Duke Energy Charter

[illegible]

To be successful in 2007 and beyond, we must:

- Establish the identity and culture of the new Duke Energy, unifying our people, values, strategy, processes and systems.
- Optimize our operations by focusing on safety, simplicity, accountability, inclusion, customer satisfaction, cost management and employee development.
- Achieve public policy, regulatory and legislative outcomes that balance our customers' needs for reliable energy at competitive prices with our shareholders' expectation of superior returns.
- Invest in energy infrastructure that meets rising customer demands for reliable energy in an energy efficient and environmentally sound manner.
- Achieve 2007 financial objectives and position the company to meet future growth targets.

In conducting our business, we value:

- ***Stewardship*** — A commitment to health, safety, environmental responsibility and our communities.
- ***Integrity*** — Ethically and honestly doing what we say we will do.
- ***Safety*** — A relentless commitment to working safely and looking out for the safety of our co-workers and others with whom we do business.
- ***Respect for the Individual*** — Embracing diversity and inclusion, enhanced by openness, sharing, trust, teamwork and involvement.
- ***High Performance*** — Achieving superior business results, stretching our capabilities and valuing the contributions of every employee.
- ***Win-Win Relationships*** — Having relationships which focus on the creation of value for all parties.
- ***Initiative*** — Having the courage, creativity and discipline to lead change and shape the future.

We will be successful when:

- Our investors realize a superior return on their investment over time.
- Our customers, suppliers and communities benefit from our business relationships.
- Every employee starts each day with a sense of purpose, and ends each day safely with a sense of accomplishment.

"Our challenges are as great as our opportunities, but I am confident that by listening to all of our stakeholders and engaging them in our efforts, we will solve the new energy equation — for the benefit of all."

Realizing the efficiencies and cost savings from the merger while maintaining our operational excellence. We are on track to realize $650 million in net savings from the Cinergy merger over the first five years. We are beginning to see the full benefits of those savings as most of the merger-related rate reductions expire this year. In 2007, we are focusing on continuous improvement. We intend to carefully manage our costs and simplify our operations to deliver our products and services as reliably and efficiently as possible.

Shaping new federal rules that limit carbon emissions to ensure our customers and other stakeholders are fairly treated. Duke Energy is the third-largest consumer of coal in the United States, so we are mindful of our environmental responsibilities. A growing body of scientific evidence suggests that the burning of fossil fuels is changing our climate. We are committed to making the best technology choices, ones that will limit our emissions and optimize our investments so that we can keep our prices competitive

Reducing greenhouse gases with advanced power generation technology will take decades and cost billions of dollars. The work will continue well into this century. But if we don't begin to solve the problem now, the costs will go even higher.

To demonstrate our corporate commitment to tackling this issue, in January 2007, Duke Energy joined the United States Climate Action Partnership (USCAP). This diverse coalition of businesses and environmental groups includes Alcoa, DuPont, Caterpillar, General Electric and other utilities — FPL Group, PG&E Corp. and PNM Resources — as well as Environmental Defense, Natural Resources Defense Council, World Resources Institute and the Pew Center on Global Climate Change. Together, we have begun a dialogue and offered recommendations on national policies for dealing with this pressing issue. Additionally, in partnership with the U.S. Department of Energy, we are researching underground carbon storage at our East Bend Station in Kentucky.

PATIENCE IS NEEDED TO CHANGE MINDS AND HABITS

The strategies I've outlined will position Duke Energy to be a leader on several fronts, including new technologies, energy efficiency, continuous improvement and sustainability. Our challenges are as great as our opportunities, but I am confident that by listening to all of our stakeholders and engaging them in our efforts, we will solve the new energy equation — for the benefit of all.

I again thank our employees, management and board of directors — both past and present — for our many successes in 2006. You achieved our strategic agenda while keeping the gas flowing and the lights on.

I thank our investors for your support during the merger and the spinoff. Your confidence in us is the best evidence that the new direction we have taken to become one of the nation's premier electric companies is the right direction.

We are energized by the prospects of a bright future. We have a solid investment proposition, and we are in a strong position to change minds and habits to create significant value for all of our stakeholders. From a sustainability standpoint, I believe that our grandchildren will be proud of how we are addressing the energy and environmental issues of our day.

James E. Rogers

James E. Rogers
Chairman, President and Chief Executive Officer

March 2, 2007

FINANCIAL HIGHLIGHTS[A]

(In millions, except per-share amounts)	2006	2005	2004	2003[C]	2002
Statement of Operations					
Operating revenues	$ 15,184	$ 16,297	$ 19,596	$ 17,623	$ 14,757
Operating expenses	12,493	13,416	16,441	16,632	12,313
Gains on sales of investments in commercial and multi-family real estate	201	191	192	84	106
Gains (losses) on sales of other assets and other, net	276	534	(416)	(199)	32
Operating income	3,168	3,606	2,931	876	2,582
Other income and expenses, net	1,008	1,609	304	550	352
Interest expense	1,253	1,066	1,282	1,331	1,116
Minority interest expense	61	338	200	62	91
Earnings from continuing operations before income taxes	2,862	3,811	1,753	33	1,727
Income tax expense (benefit) from continuing operations	843	1,282	507	(52)	544
Income from continuing operations	2,019	2,529	1,246	85	1,183
(Loss) income from discontinued operations, net of tax	(156)	(701)	244	(1,246)	(149)
Income (loss) before cumulative effect of change in accounting principle	1,863	1,828	1,490	(1,161)	1,034
Cumulative effect of change in accounting principle,					
net of tax and minority interest	—	(4)	—	(162)	—
Net income (loss)	1,863	1,824	1,490	(1,323)	1,034
Dividends and premiums on redemption of preferred and preference stock	—	12	9	13	13
Earnings (loss) available for common stockholders	$ 1,863	$ 1,812	$ 1,481	$ (1,336)	$ 1,021
Ratio of Earnings to Fixed Charges[B]	3.2	4.7	2.3	—[B]	2.0
Common Stock Data					
Shares of common stock outstanding[E]					
Year-end	1,257	928	957	911	895
Weighted average – basic	1,170	934	931	903	836
Weighted average – diluted	1,188	970	966	904	838
Earnings (loss) per share					
Basic	$ 1.59	$ 1.94	$ 1.59	$ (1.48)	$ 1.22
Diluted	$ 1.57	$ 1.88	$ 1.54	$ (1.48)	$ 1.22
Dividends per share	$ 1.26	$ 1.17	$ 1.10	$ 1.10	$ 1.10
Balance Sheet					
Total assets	$ 68,700	$ 54,723	$ 55,770	$ 57,485	$ 60,122
Long-term debt including capital leases, less current maturities	$ 18,118	$ 14,547	$ 16,932	$ 20,622	$ 20,221
Capitalization					
Common equity	55%	50%	45%	37%	36%
Preferred stock	0%	0%	0%	0%	1%
Trust preferred securities	0%	0%	0%	0%	3%
Total common equity and preferred securities	55%	50%	45%	37%	40%
Minority interests	2%	2%	4%	5%	5%
Total debt	43%	48%	51%	58%	55%

[A] Significant transactions reflected in the results above include: 2006 merger with Cinergy (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions"), 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions"), 2005 DENA disposition (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Discontinued Operations and Assets Held for Sale"), 2005 deconsolidation of DEFS effective July 1, 2005 (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions"), 2005 DEFS sale of TEPPCO (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions") and 2004 DENA sale of the Southeast plants (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions").

[B] Earnings were inadequate to cover fixed charges by $2.1 billion for the year ended December 31, 2003.

[C] As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force (EITF) 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). In accordance with the transition guidance for these standards, Duke Energy recorded a net of tax and minority interest cumulative effect adjustment for change in accounting principles. (See Note 1 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Summary of Significant Accounting Policies," for further discussion.)

[D] Includes pre-tax gains of approximately $0.9 billion, net of minority interest, related to the sale of TEPPCO GP and LP in 2005 (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions").

[E] 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K, "Acquisitions and Dispositions").

See Notes to Consolidated Financial Statements in Duke Energy's 2006 Form 10-K.

DUKE ENERGY BUSINESS SEGMENTS

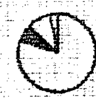
U.S. Franchised Electric and Gas

2007 EBIT CONTRIBUTION

U.S. Franchised Electric and Gas, which operates in North Carolina, South Carolina, Indiana, Ohio and Kentucky, is our largest business segment and our primary source of earnings growth. We expect this segment to represent approximately 79 percent of forecasted 2007 ongoing total segment earnings before interest and taxes (EBIT).* It includes:

- A $16 billion retail rate base
- 3.9 million electric customers
- 500,000 gas customers in Ohio and Kentucky
- 47,000 square miles of service territory
- 28,000 megawatts of regulated generation.

Commercial Power

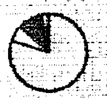


2007 EBIT CONTRIBUTION

Duke Energy's Commercial Power business owns and operates unregulated power plants, primarily in the Midwest. Almost all of the results for this business come from sales to retail customers in Ohio under that state's Rate Stabilization Plan. Also in this segment is Duke Energy Generation Services (DEGS), which develops, owns and operates electric generation sources that serve large energy consumers, municipalities, utilities and industrial facilities. We expect this segment to represent approximately 7 percent of forecasted 2007 ongoing total segment EBIT.* It includes:

- 8,100 megawatts of unregulated generation, most of which is dedicated to regulated customers.

Duke Energy International



2007 EBIT CONTRIBUTION

Duke Energy's international electric generation operations are located in Central and South America. We expect this segment to represent approximately 11 percent of forecasted 2007 ongoing total segment EBIT.* It includes:

- Approximately 4,000 megawatts of generation, primarily hydroelectric power, in six countries: Argentina, Brazil, Ecuador, El Salvador, Guatemala and Peru.

Crescent Resources

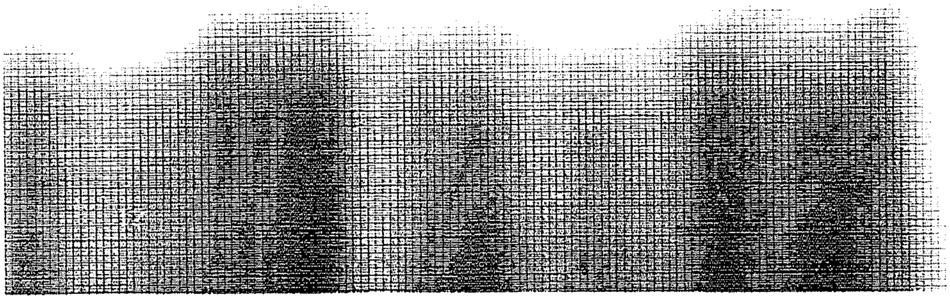
2007 EBIT CONTRIBUTION

Formed more than 40 years ago by Duke Energy, Crescent Resources manages land holdings and develops high-quality commercial, residential and multi-family real estate projects. We expect this segment to represent approximately 3 percent of forecasted 2007 ongoing total segment EBIT.* In 2006, Duke Energy worked with Morgan Stanley Real Estate Fund to create an effective 50/50 joint venture.

- Crescent Resources is in 10 states, primarily in the southeastern and southwestern United States.

Taking the U.S. Franchised Electric and Gas and Commercial Power segments together, we expect more than 85 percent of Duke Energy's forecasted 2007 ongoing total segment EBIT will come from sales to regulated customers.

*2007 forecasted ongoing total segment EBIT excludes results for the operations labeled Other.



DUKE ENERGY AT A GLANCE:

Repositioning our business

In January 2007, Duke Energy Corporation became one of the largest pure-play electric power holding companies in the United States. Our utility companies supply and deliver energy to 3.9 million U.S. customers. We have about 37,000 megawatts of electric generating capacity in the Midwest and the Carolinas, natural gas distribution services in Ohio and Kentucky, and approximately 4,000 megawatts of electric generation in Latin America. Duke Energy is also a joint-venture partner in a U.S. real estate company.

GIANNA MANES IS SENIOR VICE PRESIDENT OF REGULATED PORTFOLIO OPTIMIZATION AND FUELS AT DUKE ENERGY'S U.S. FRANCHISED ELECTRIC AND GAS BUSINESS. THE ORGANIZATION SHE LEADS BUYS AND SELLS ELECTRICITY IN THE WHOLESALE MARKET AND PURCHASES COAL AND NATURAL GAS FOR THE GENERATION FLEET.

Changing minds by thinking differently

Over the next three years, Duke Energy's regulated businesses plan to invest more than $9 billion to strengthen customer service and reliability, and to meet steadily growing demand. Besides investing in additional megawatt-hours from new plants, we are supporting a "save-a-watt" business model focused on energy efficiency to offset the need for more plants, even as demand continues to grow. With this new model, energy efficiency becomes a sustainable system resource that plays a more significant role in our plans to meet customers' increasing demand for electricity.

We are working with policymakers to find the best way to address the timely recovery of these investments. We believe that recovering financing costs as we build and implementing a regulatory framework that encourages investments in energy efficiency will result in smaller, more manageable rate increases. This is a win-win proposition for our customers and our investors. We also believe that investments in energy efficiency should be put on an equal footing with investments in new generation. With comparable earnings on investments, we would be economically impartial to meeting our customers' growing demand for electricity with investments in energy efficiency or new generation.

BEVERLY MARSHALL (LEFT), VICE PRESIDENT FOR FEDERAL POLICY AND GOVERNMENT AFFAIRS AT DUKE ENERGY, AND JULIE GRIFFITH, VICE PRESIDENT FOR STATE GOVERNMENT AFFAIRS AT DUKE ENERGY INDIANA, ARE TWO KEY MEMBERS OF DUKE ENERGY'S PUBLIC POLICY TEAM.

Defining the new energy equation

For more than a century, we have supplied our customers with affordable and reliable electricity. Our product is considered an essential service. It has also made possible many innovative technologies that enhance our customers' standard of living. And it has helped keep our local and state economies competitive in the global marketplace.

Providing adequate power was once as simple as balancing supply and demand. Although that is still the core of what we do, times have changed. Today, we face the unprecedented challenge of solving a new energy equation.

During a time of rising and volatile fuel prices, historic environmental challenges and industry restructuring, the demand for electricity continues to grow. With our commitment to sustainability, we must balance the growing demand for power with the investments needed to supply it — while reducing our environmental impact and keeping prices affordable.

This requires new thinking on both the policy and technology fronts.

To meet the growing demand for power, we are investing in a new generation of highly efficient and environmentally advanced power plants, new environmental controls for existing plants, and transmission and distribution system upgrades. Our emphasis on new energy efficiency programs and technologies will help meet growing demand.

We call energy efficiency the "fifth fuel" because it complements coal, nuclear power, natural gas and renewable energy, the four primary sources of electric power for the future. We see it as one of our most promising solutions, because the most environmentally sound, inexpensive and reliable kilowatt-hour is the one we don't have to produce. Generating "save-a-watts" is just one part of the equation that requires our customers to change how they use electricity. We are looking at ways to help them do that.

UNDERSTANDING THE VARIABLES

Solving the new energy equation means understanding all of its variables. One of the most significant and unpredictable variables is future environmental regulation. Today's irregular patchwork of federal and state environmental requirements has already prompted substantial investments.

Recognition of global warming as a serious problem has increased the call for regulation of greenhouse gases, primarily carbon. Mandatory carbon dioxide (CO_2) emission reductions are being considered in Congress. When legislation passes, utilities will need to make substantial investments to comply. It is critical that any such carbon regulations be phased in to avoid causing economic disruption and that the affected companies receive emission allowances to defray the cost of compliance.

POLICY LEADERSHIP

Our stakeholders, particularly our customers, investors and communities, expect us to play a leading role in shaping a national policy that addresses this national and global challenge. We take that responsibility seriously. Our goal is a policy that will slow the growth of greenhouse gases and then begin to reduce them — while protecting the economy and our customers from price shocks.

Another variable is the prospect of mandatory renewable portfolio standards (RPS) at both the federal and state level. Twenty-two states currently have such standards, which require electric utilities to generate anywhere from 5 to 20 percent of their power from "climate-friendly" renewable energy sources such as solar, wind, geothermal and agricultural waste, over varying periods of time. Congress is evaluating legislative proposals for a national RPS.

As a company focused on sustainability, we have invested in pilot projects involving wind and agricultural waste so that we can gain an understanding of the technologies and costs that would be required on a larger scale before mandatory standards are put in place. Today, we are also the second-largest generator of renewable hydroelectric power in the United States.

Like any other publicly traded company, we have a responsibility to meet our customers' needs while recovering our investments and earning a good return on those investments for our shareholders. To solve the new energy equation, we must use nuclear, coal, natural gas, renewable energy and energy efficiency. Our strategy for doing so is outlined on the following pages.

Balancing supply and demand

When you flip that light switch, adjust your air conditioning, turn your television on or boot up your computer, you expect power. But do you think about where it comes from? Duke Energy generates electricity from a variety of fuels: coal, natural gas, nuclear and renewable hydroelectric sources. Energy efficiency, the "fifth fuel," is also part of the mix. This diversity means that we're not overly dependent on any single fuel, and it helps us address fuel price fluctuations and environmental risks. We must also keep our fuel mix in balance to meet steadily growing demand. This is all part of the company's Integrated Resource Plan, which determines the best options to meet our customers' electricity needs over the next 20 years. Using input from many stakeholders, we update the plan periodically with the goal of finding the most efficient and economical resources — both in power generation and in energy efficiency — to meet future demand.

JANICE HAGER IS MANAGING DIRECTOR OF INTEGRATED RESOURCE PLANNING FOR DUKE ENERGY.
HER TEAM ENSURES THAT DUKE ENERGY'S SUPPLY OF ELECTRICITY KEEPS PACE WITH GROWING CUSTOMER DEMAND
WHILE COMPLYING WITH ENVIRONMENTAL REQUIREMENTS.

Balancing regulated and non-regulated assets

When electric generation was deregulated in Ohio in 2001, many people expected a fully competitive market to develop in the first five years. But that didn't happen. As the end of that five-year period drew near, regulators, utilities and customers realized that an immediate shift to market-based rates in 2006 would probably result in large price increases over a short time, as had occurred in other states. To minimize rate shock and to permit a gradual transition to market-based rates, state regulators worked with Ohio's electric utilities, including Duke Energy Ohio, to develop rate stabilization plans (RSPs). These plans provide customers with stable, predictable rates for a number of years — in Duke Energy's case, from 2006 through 2008. In late 2006, Duke Energy Ohio asked regulators to extend its RSP by an additional two years, through 2010. Under the proposed extension, which is being reviewed, the utility's unregulated generating assets in Ohio would continue to serve the state's retail customers. The plan supports continued electric system reliability and sends clear price signals to customers, while helping to maintain a stable revenue stream for the company.

DAVE CELONA, VICE PRESIDENT FOR GOVERNMENT AND REGULATORY AFFAIRS
AT DUKE ENERGY OHIO, IS WORKING TO PROVIDE STABILITY TO OHIO'S ELECTRIC INDUSTRY BY PROMOTING
THE EXTENSION OF THE COMPANY'S RATE STABILIZATION PLAN.

Balancing reliability and cost

Just as demand for electric power is increasing, so is the demand for even greater reliability of that power supply. This is primarily driven by our increasingly digital society. More and more appliances and equipment — from plasma televisions to automated assembly lines — are using more kilowatt-hours to power more digital circuits. A power interruption of even a few seconds is not only inconvenient, but it can have a major economic impact as well. At Duke Energy, we work around the clock to supply power reliably. One way we do that is to ensure that we operate our supply and delivery operations — generation, transmission and distribution — efficiently and safely, and in a way that protects the environment. This balanced approach helps keep our reliability and customer satisfaction high, and it helps us better manage our operation and maintenance costs, which is important to our investors. Our power delivery networks play a critical role in our energy efficiency and reliability efforts. Investing in a smart grid will help us achieve our "fifth fuel" initiatives and enhance our service and reliability.

THEOPOLIS HOLEMAN IS SENIOR VICE PRESIDENT OF POWER DELIVERY FOR DUKE ENERGY'S U.S. FRANCHISED ELECTRIC AND GAS OPERATIONS. HIS TEAM IS RESPONSIBLE FOR KEEPING POWER QUALITY AND RELIABILITY HIGH — 24/7.

Changing habits with a smarter grid

We believe we can change energy habits, including our own, by deploying new energy-saving technologies. One promising technology available now is advanced metering — the replacement of the simple billing meter with one capable of two-way communication over our distribution grid. The day when all of our customers will be able to log in to our Web site and see their hourly energy use is not far off.

With our customers' permission, these new meters would give us the ability to control high-energy-use appliances and equipment during peak demand times, without inconveniencing customers or business owners, who would also share in the savings.

Smart meters will also enhance our ability to measure and verify the impacts of our energy efficiency programs. This is critical for energy efficiency to become a reliable system resource for meeting customer demand for electricity. Remote metering over our network would also let us predict trouble, pinpoint outages and restore power faster. This solution should be more economical than paying for a new power plant, and most of the smart grid's cost would be offset by the operational and power procurement savings.

Advanced metering is just one of the energy- and cost-saving technologies we are exploring to change minds and habits.

DAVID MOHLER (LEFT) IS VICE PRESIDENT AND CHIEF TECHNOLOGY OFFICER AT DUKE ENERGY. TED SCHULTZ IS VICE PRESIDENT FOR ENERGY EFFICIENCY. THEIR TEAMS ARE COMMITTED TO DEPLOYING THE BEST PRACTICES AND TECHNOLOGIES TO HELP OUR CUSTOMERS USE ENERGY MORE WISELY.

Solving the new energy equation

It is clear that we need to invest in enhanced reliability and in the expansion of our capacity to generate electricity to meet growing customer demand. We know that investments in new state-of-the-art generation, renewables and energy efficiency can be made reasonably with appropriate and timely cost recovery.

Historically, regulators have rewarded utilities for selling more of their product, not less. To solve the new energy equation, we need to change minds about the types of investments that should be eligible for recovery through rates.

We are especially interested in building public support for investments in energy efficiency — the "fifth fuel," which lowers overall customer demand and reduces or eliminates greenhouse gases and other emissions.

We are working to shift the paradigm in the way regulators treat the business of energy efficiency and in the way utilities develop and deliver such programs. We believe utilities are uniquely positioned to provide universal access to energy efficiency services and new technologies to their customers. This would dramatically change the way utilities develop and deliver energy efficiency programs as part of their standard customer offerings.

To create a sustainable "fifth fuel" system resource accessible by all customers, energy efficiency investments must be on par with new generation investments.

STRIKING A BALANCE

Changing the regulatory paradigm will also help us avoid some of the price jumps that can occur when a new plant, project, initiative or program finally gets up and running. Such constructive regulatory treatment would give us and others in our industry further incentives to explore and invest in these programs and projects.

BUILDING A CONSENSUS

To achieve this goal, we are collaborating with numerous stakeholder groups. We hope to build a consensus that will convince lawmakers and regulators that everyone wins with appropriate regulatory treatment of investments in efficiency and renewable energy.

Our new chief technology officer and new vice president of energy efficiency and their teams are committed to achieving success on these two fronts. They know that our customers need innovative products and services to help them better manage their energy costs and reduce their own environmental footprints — while maintaining the comfort and conveniences they want and expect.

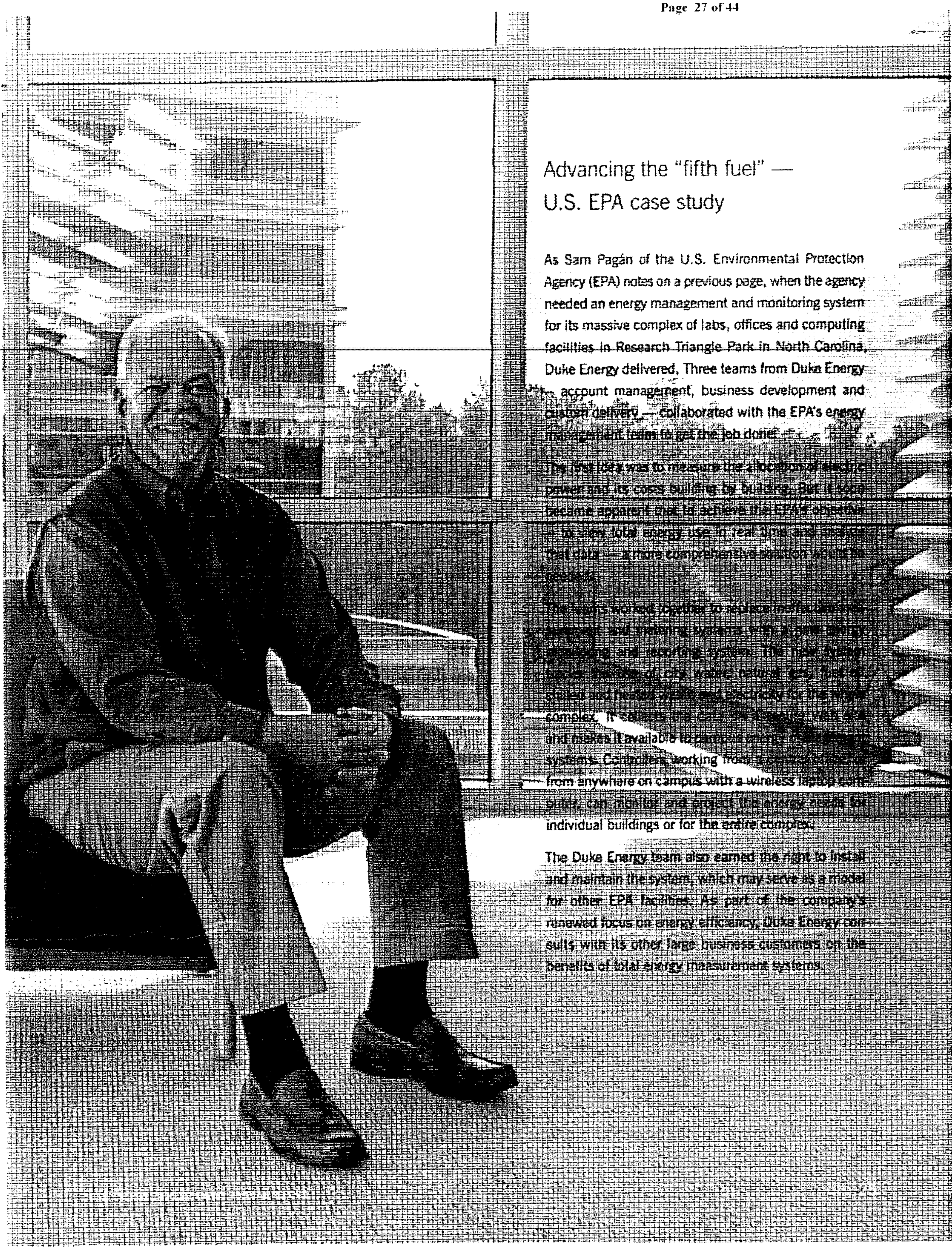
We believe that this balanced strategy is a winning proposition for all stakeholders. Our customers will save money, the environment will be cleaner and our investors will earn fair returns on their investments.

Duke Energy provides the solution

The U.S. Environmental Protection Agency (EPA) facility at Research Triangle Park in North Carolina is the agency's major center for air pollution research and regulation. With 1.2 million square feet for laboratories, computing facilities and offices, it is the largest facility ever designed and built by the EPA. To lead by example, the EPA designed the complex — which was completed in 2001 — to operate with sustainable building practices, including energy efficiency. "The key to energy efficiency is having the right information," says Sam Pagán, the facility's energy director. "Our plans called for a unified system to monitor and meter all of our energy use, and we tried numerous vendors and technologies. Duke Energy was the only company to come up with and deliver a viable solution — a Web-based system that monitors in real time how much water, natural gas, fuel oil and electricity we are using. We now have the mechanism to better manage our annual energy needs and save the EPA considerable energy dollars."

SAM PAGÁN IS DIRECTOR OF THE ENERGY MANAGEMENT AND CONSERVATION STAFF AT THE EPA'S RESEARCH TRIANGLE PARK FACILITY IN NORTH CAROLINA. THE SPRAWLING COMPLEX OF LABS, OFFICES AND COMPUTING FACILITIES USES AN ENERGY-MONITORING SOLUTION CREATED BY DUKE ENERGY.

(FROM LEFT) JOHN BOONE, BUSINESS DEVELOPMENT MANAGER, TOM FENIMORE, MANAGER OF ENERGY MANAGEMENT SERVICES, AND KEN KERNODLE, CUSTOMER RELATIONS MANAGER, WORKED ON THE DUKE ENERGY TEAMS THAT DESIGNED, DEVELOPED AND DELIVERED AN ENERGY MANAGEMENT SOLUTION FOR THE EPA.



Advancing the "fifth fuel" — U.S. EPA case study

As Sam Pagán of the U.S. Environmental Protection Agency (EPA) notes on a previous page, when the agency needed an energy management and monitoring system for its massive complex of labs, offices and computing facilities in Research Triangle Park in North Carolina, Duke Energy delivered. Three teams from Duke Energy — account management, business development and custom delivery — collaborated with the EPA's energy management team to get the job done.

The first idea was to measure the allocation of electric power and its costs building by building. But it soon became apparent that to achieve the EPA's objective — to view total energy use in real time and analyze that data — a more comprehensive solution would be needed.

The teams worked together to replace [illegible] and metering systems with a new energy [illegible] and reporting system. The new system tracks the use of city water, natural gas, fuel oil, chilled and heated water and electricity for the whole complex. It collects the data [illegible] and makes it available to campus energy [illegible] systems. Controllers, working from a [illegible] or from anywhere on campus with a wireless laptop computer, can monitor and project the energy needs for individual buildings or for the entire complex.

The Duke Energy team also earned the right to install and maintain the system, which may serve as a model for other EPA facilities. As part of the company's renewed focus on energy efficiency, Duke Energy consults with its other large business customers on the benefits of total energy measurement systems.

Meeting steadily growing demand

Plans to modernize our Cliffside Steam Station in North Carolina will ensure that our customers in the Carolinas have an affordable and reliable supply of power to support the region's economic growth. Our plan called for replacing four old coal units with two supercritical and highly efficient 800-megawatt coal units using advanced emissions controls.

In late February 2007, we received a notice of decision from the North Carolina Utilities Commission, which authorized building one of the two units. The commission also accepted our commitment to invest 1 percent of our revenues in the Carolinas for energy efficiency, subject to appropriate regulatory treatment, and our plan to retire older, less efficient units.

Our estimates were based on two units, and as this annual report was being published, we still needed an air permit for this project. We are studying the commission's decision and the project to determine how to proceed. We won't make a decision until we have a clearer understanding of the overall costs as well as the conditions of the air permit. We are also evaluating the possibility of enhancing and accelerating natural gas-fired plants in our portfolio.

Another important element of our generation strategy is the 2,234-megawatt William States Lee nuclear plant we are proposing to build in South Carolina's Cherokee County. We also continue to explore building an advanced cleaner coal plant in Indiana, and we are pursuing additional energy efficiency programs and renewable technologies.

The net result of these initiatives will help us meet steadily increasing customer demand while reducing multiple environmental impacts of our operations, including carbon emissions.

RICK ROPER IS GENERAL MANAGER OF DUKE ENERGY'S CLIFFSIDE STEAM STATION IN WESTERN NORTH CAROLINA. THE 760-MEGAWATT BASE LOAD POWER PLANT HAS BEEN IN COMMERCIAL OPERATION SINCE 1940.

Challenging conventional wisdom

Our customers want us to solve the new energy equation, and our track record gives them confidence that we can do it. They want better information about their own energy use and more options to control it. For Duke Energy, that means not only providing our customers with electricity, but also showing them how to personalize their energy use. That's our commitment.

We will start by digitizing our electric distribution and transmission grids. These huge networks already link meters, transformers, substations and other technologies with a communication and control infrastructure. By taking our mostly analog distribution grid and converting it to a digital network, we can create an information-rich communication system. Our plan is to create the "utility of the future."

UTILITY OF THE FUTURE

As the electric grid goes digital, we can meet our customers' growing appetite for better energy-efficiency information, programs and technologies; for plug-in electric hybrid vehicles; for distributed generation, which is power produced from smaller and more localized generating units, and for more base load power generated from renewable sources.

A NEW BUSINESS MODEL

The utility of the future will focus on generating, delivering and using energy more efficiently. The business model is based on capturing information and relaying it to our customers, who can use it to make better energy decisions. This model will also help us balance supply and demand, and respond faster to service interruptions.

For example, new "smart meters" will tell customers exactly how much electricity they are using at any given time. These meters will also tell us when, how and in what quantities customers are using power. This will allow us to provide exactly what they need along the most efficient distribution circuits. In essence, the meter becomes an interactive information gateway, not just a passive billing device. The usage data we compile will also help us make better long-term decisions about the need for new transmission and distribution systems.

The utility of the future will make us all more efficient. Already on the drawing board are designs for new transformers that will convert voltages with greater efficiency for homes and businesses. New electric wire alloys will let us transmit power with less resistance. All of the components of the energy delivery system will be linked through real time communication over wires already in place in every home and business.

We have several other initiatives already under way, including our broadband-over-power-line (BPL) pilot programs in Charlotte, N.C., and Cincinnati, Ohio. Our energy monitoring and metering solution at the EPA labs and computing center at Research Triangle Park in North Carolina (see pages 23-25) can be the platform for the expansion of this technology to residential, commercial and industrial customers.

FORMING ALLIANCES

Our imaginative initiatives aren't limited to smart metering and exploring new technologies. To promote energy efficiency, we are forming new collaboratives with our stakeholders, including alliances with retailers and suppliers, to inform customers — both small and large — of readily available tools and technologies to reduce energy use.

Duke Energy is well positioned to solve energy problems for our customers. We understand energy use, we have a low cost of capital, and we are working through alliances and with third parties to implement the best solutions for customers.

The long-term goal for the utility of the future is simple: to provide greater reliability with less environmental impact at a lower cost to our customers. New programs delivered through new channels will make it happen.

Balancing customer and shareholder interests

Our primary goals are to deliver competitively priced, reliable energy to our customers while protecting the environment and earning reasonable returns for our investors. In this growing economy, we need to make major investments in a new generation of power plants, as well as in our transmission and distribution systems, in order to meet increasing customer demands for energy. Given the uncertainties about future environmental regulations, we also want to expand our portfolio to include more energy-efficient products and services, and more renewable energy options. We are convinced that a diverse resource portfolio will be more cost-effective and sustainable over the long term. The new challenges we face demand new regulatory solutions. Too often, traditional regulatory policies pit customer interests against shareholder interests. We are committed to finding regulatory strategies that align the interests of customers and shareholders, resulting in benefits to both in all five states where we do business.

KAY PASHOS IS VICE PRESIDENT FOR REGULATORY STRATEGY AT DUKE ENERGY.
HER TEAM IS RESPONSIBLE FOR PERSUADING STATE REGULATORS TO APPROVE THE COMPANY'S REGULATORY STRATEGY,
WHICH TAKES INTO ACCOUNT THE NEEDS OF BOTH CUSTOMERS AND SHAREHOLDERS.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
(in millions, except per-share amounts)	2006	2005	2004
Operating Revenues			
Non-regulated electric, natural gas, natural gas liquids, and other	$ 3,158	$ 7,212	$11,322
Regulated electric	7,578	5,406	5,041
Regulated natural gas and natural gas liquids	4,348	3,679	3,233
Total operating revenues	15,184	16,297	19,596
Operating Expenses			
Natural gas and petroleum products purchased	1,829	5,827	9,225
Operation, maintenance and other	4,415	3,540	3,313
Fuel used in electric generation and purchased power	3,403	1,510	1,576
Depreciation and amortization	2,049	1,728	1,760
Property and other taxes	769	571	513
Impairments and other charges	28	140	64
Total operating expenses	12,493	13,416	16,441
Gains on Sales of Investments in Commercial and Multi-Family Real Estate	201	191	192
Gains (Losses) on Sales of Other Assets and Other, net	276	534	(416)
Operating Income	3,168	3,606	2,931
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	732	479	161
(Losses) Gains on sales and impairments of equity investments	(20)	1,225	(4)
Gain on sale of subsidiary stock	15	—	—
Other income and expenses, net	281	105	147
Total other income and expenses	1,008	1,809	304
Interest Expense	1,253	1,066	1,282
Minority Interest Expense	61	538	200
Earnings From Continuing Operations Before Income Taxes	2,862	3,811	1,753
Income Tax Expense from Continuing Operations	843	1,282	507
Income From Continuing Operations	2,019	2,529	1,246
(Loss) Income From Discontinued Operations, net of tax	(156)	(701)	244
Income Before Cumulative Effect of Change in Accounting Principle	1,863	1,828	1,490
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest	—	(4)	—
Net Income	1,863	1,824	1,490
Dividends and Premiums on Redemption of Preferred and Preference Stock	—	12	9
Earnings Available For Common Stockholders	$ 1,863	$ 1,812	$ 1,481
Common Stock Data			
Weighted-average shares outstanding			
Basic	1,170	934	931
Diluted	1,188	970	966
Earnings per share (from continuing operations)			
Basic	$ 1.73	$ 2.69	$ 1.33
Diluted	$ 1.70	$ 2.60	$ 1.29
(Loss) earnings per share (from discontinued operations)			
Basic	$ (0.14)	$ (0.75)	$ 0.26
Diluted	$ (0.13)	$ (0.72)	$ 0.25
Earnings per share (before cumulative effect of change in accounting principle)			
Basic	$ 1.59	$ 1.94	$ 1.59
Diluted	$ 1.57	$ 1.88	$ 1.54
Earnings per share			
Basic	$ 1.59	$ 1.94	$ 1.59
Diluted	$ 1.57	$ 1.88	$ 1.54
Dividends per share	$ 1.26	$ 1.17	$ 1.10

See Notes to Consolidated Financial Statements in Duke Energy's 2006 Form 10-K.

CONSOLIDATED BALANCE SHEETS

(In millions, except per-share amounts)	December 31, 2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 948	$ 511
Short-term investments	1,514	632
Receivables (net of allowance for doubtful accounts of $94 at December 31, 2006 and $127 at December 31, 2005)	2,256	2,580
Inventory	1,358	863
Assets held for sale	28	1,528
Unrealized gains on mark-to-market and hedging transactions	107	87
Other	729	1,756
Total current assets	6,940	7,957
Investments and Other Assets		
Investments in unconsolidated affiliates	2,305	1,933
Nuclear decommissioning trust funds	1,775	1,504
Goodwill	8,175	3,775
Intangibles, net	905	55
Notes receivable	224	138
Unrealized gains on mark-to-market and hedging transactions	248	62
Assets held for sale	134	3,597
Investments in residential, commercial and multi-family real estate (net of accumulated depreciation of $17 at December 31, 2005)	—	1,281
Other	2,304	2,678
Total investments and other assets	16,070	15,033
Property, Plant and Equipment		
Cost	58,330	40,828
Less accumulated depreciation and amortization	16,883	11,623
Net property, plant and equipment	41,447	29,205
Regulatory Assets and Deferred Debits		
Deferred debt expense	320	269
Regulatory assets related to income taxes	1,361	1,338
Other	2,562	928
Total regulatory assets and deferred debits	4,243	2,535
Total Assets	$68,700	$54,723
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 1,686	$ 2,431
Notes payable and commercial paper	450	83
Taxes accrued	434	327
Interest accrued	302	230
Liabilities associated with assets held for sale	26	1,488
Current maturities of long-term debt	1,605	1,400
Unrealized losses on mark-to-market and hedging transactions	134	204
Other	1,976	2,295
Total current liabilities	6,613	8,418
Long-term Debt	18,118	14,547
Deferred Credits and Other Liabilities		
Deferred income taxes	7,003	5,253
Investment tax credit	175	144
Unrealized losses on mark-to-market and hedging transactions	238	10
Liabilities associated with assets held for sale	18	2,085
Asset retirement obligations	2,301	2,058
Other	7,327	5,020
Total deferred credits and other liabilities	17,062	14,570
Commitments and Contingencies		
Minority Interests	805	749
Common Stockholders' Equity		
Common stock, $0.001 par value, 2 billion shares authorized; 1,257 million and zero shares outstanding at December 31, 2006 and December 31, 2005, respectively	1	—
Common stock, no par, 2 billion shares authorized; zero and 928 million shares outstanding at December 31, 2006 and December 31, 2005, respectively	—	10,446
Additional paid-in capital	19,854	—
Retained earnings	5,652	5,277
Accumulated other comprehensive income	595	716
Total common stockholders' equity	26,102	16,439
Total Liabilities and Common Stockholders' Equity	$68,700	$54,723

See Notes to Consolidated Financial Statements in Duke Energy's 2006 Form 10-K.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
(In millions)	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,863	$ 1,824	$ 1,490
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including amortization of nuclear fuel)	2,215	1,884	2,037
Cumulative effect of change in accounting principle	—	4	—
Gains on sales of investments in commercial and multi-family real estate	(201)	(191)	(201)
Gains on sales of equity investments and other assets	(365)	(1,771)	(193)
Impairment charges	48	159	194
Deferred income taxes	250	282	867
Minority interest	61	538	195
Equity in earnings of unconsolidated affiliates	(732)	(479)	(161)
Purchased capacity levelization	(14)	(14)	92
Contributions to company-sponsored pension plans	(172)	(45)	(279)
(Increase) decrease in:			
Net realized and unrealized mark-to-market and hedging transactions	(134)	443	216
Receivables	844	(549)	(231)
Inventory	(24)	(80)	(49)
Other current assets	1,276	(844)	(53)
Increase (decrease) in:			
Accounts payable	(1,524)	117	(5)
Taxes accrued	(69)	53	188
Other current liabilities	(594)	622	91
Capital expenditures for residential real estate	(322)	(355)	(322)
Cost of residential real estate sold	143	294	258
Other, assets	1,005	193	(155)
Other, liabilities	194	533	158
Net cash provided by operating activities	3,748	2,818	4,168
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(3,381)	(2,327)	(2,161)
Investment expenditures	(89)	(43)	(46)
Acquisitions, net of cash acquired	(284)	(294)	—
Cash acquired from acquisition of Cinergy	147	—	—
Purchases of available-for-sale securities	(33,436)	(40,317)	(65,929)
Proceeds from sales and maturities of available-for-sale securities	32,596	40,131	65,098
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable	2,861	2,375	1,619
Proceeds from the sales of commercial and multi-family real estate	254	372	606
Settlement of net investment hedges and other investing derivatives	(163)	(296)	—
Distributions from equity investments	152	383	—
Purchases of emission allowances	(228)	(18)	—
Sales of emission allowances	194	—	—
Other	49	(92)	20
Net cash used in investing activities	(1,328)	(126)	(793)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the:			
Issuance of long-term debt	2,369	543	153
Issuance of common stock and common stock related to employee benefit plans	127	41	1,704
Payments for the redemption of:			
Long-term debt	(2,098)	(1,346)	(3,646)
Preferred stock of a subsidiary	(12)	(134)	(176)
Decrease in cash overdrafts	(2)	—	—
Notes payable and commercial paper	(412)	165	(67)
Distributions to minority interests	(304)	(861)	(1,477)
Contributions from minority interests	247	779	1,277
Dividends paid	(1,488)	(1,105)	(1,065)
Repurchase of common shares	(500)	(933)	—
Proceeds from Duke Energy Income Fund	104	110	—
Other	8	24	19
Net cash used in financing activities	(1,961)	(2,717)	(3,278)
Changes in cash and cash equivalents included in assets held for sale	(22)	3	37
Net increase (decrease) in cash and cash equivalents	437	(22)	136
Cash and cash equivalents at beginning of period	511	533	397
Cash and cash equivalents at end of period	$ 948	$ 511	$ 533
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 1,154	$ 1,086	$ 1,323
Cash paid (refunded) for income taxes	$ 460	$ 546	$ (339)
Acquisition of Cinergy Corp.			
Fair value of assets acquired	$ 17,304	$ —	$ —
Liabilities assumed	$ 12,709	$ —	$ —
Issuance of common stock	$ 8,993	$ —	$ —
Significant non-cash transactions:			
Conversion of convertible notes to stock	$ 632	$ 28	$ —
AFUDC-equity component	$ 58	$ 30	$ 25
Transfer of DEFS Canadian Facilities	$ —	$ 97	$ —
Debt retired in connection with disposition of business	$ —	$ —	$ 840
Note receivable from sale of southeastern plants	$ —	$ —	$ 48
Remarketing of senior notes	$ —	$ —	$ 1,625

See Notes to Consolidated Financial Statements in Duke Energy's 2006 Form 10-K.

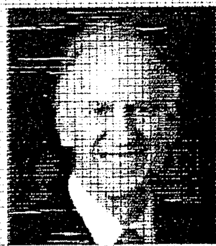
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME

					Accumulated Other Comprehensive Income (Loss)					
(In millions)	Common Stock Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Foreign Currency Adjustments	Net Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	SFAS No. 158 Adjustment	Other	Total
Balance December 31, 2003	**911**	**$ 9,513**	**$ —**	**$ 4,066**	**$315**	**$ 298**	**$(444)**	**$ —**	**$ —**	**$ 13,748**
Net income	—	—	—	1,490	—	—	—	—	—	1,490
Other Comprehensive Income										
Foreign currency translation adjustments	—	—	—	—	279	—	—	—	—	279
Foreign currency translation adjustments reclassified into earnings as a result of the sale of Asia-Pacific Business	—	—	—	—	(54)	—	—	—	—	(54)
Net unrealized gains on cash flow hedges[b]	—	—	—	—	—	311	—	—	—	311
Reclassification into earnings from cash flow hedges[c]	—	—	—	—	—	(83)	—	—	—	(83)
Minimum pension liability adjustment[d]	—	—	—	—	—	—	28	—	—	28
Total comprehensive income										1,971
Dividend reinvestment and employee benefits	5	128	—	—	—	—	—	—	—	128
Equity offering	41	1,625	—	—	—	—	—	—	—	1,625
Common stock dividends	—	—	—	(1,018)	—	—	—	—	—	(1,018)
Preferred and preference stock dividends	—	—	—	(9)	—	—	—	—	—	(9)
Other capital stock transactions, net	—	—	—	(4)	—	—	—	—	—	(4)
Balance December 31, 2004	**957**	**$11,266**	**$ —**	**$ 4,525**	**$540**	**$ 526**	**$(416)**	**$ —**	**$ —**	**$ 16,441**
Net income	—	—	—	1,824	—	—	—	—	—	1,824
Other Comprehensive Income										
Foreign currency translation adjustments[a]	—	—	—	—	306	—	—	—	—	306
Net unrealized gains on cash flow hedges[b]	—	—	—	—	—	413	—	—	—	413
Reclassification into earnings from cash flow hedges[c]	—	—	—	—	—	(1,026)	—	—	—	(1,026)
Minimum pension liability adjustment[d]	—	—	—	—	—	—	356	—	—	356
Other[f]	—	—	—	—	—	—	—	—	17	17
Total comprehensive income										1,890
Dividend reinvestment and employee benefits	3	85	—	—	—	—	—	—	—	85
Stock repurchase	(33)	(933)	—	—	—	—	—	—	—	(933)
Conversion of debt	1	28	—	—	—	—	—	—	—	28
Common stock dividends	—	—	—	(1,093)	—	—	—	—	—	(1,093)
Preferred and preference stock dividends	—	—	—	(12)	—	—	—	—	—	(12)
Other capital stock transactions, net	—	—	—	33	—	—	—	—	—	33
Balance December 31, 2005	**928**	**$10,446**	**$ —**	**$ 5,277**	**$846**	**$ (87)**	**$ (60)**	**$ —**	**$ 17**	**$ 16,439**
Net income	—	—	—	1,863	—	—	—	—	—	1,863
Other Comprehensive Income										
Foreign currency translation adjustments	—	—	—	—	103	—	—	—	—	103
Net unrealized gains on cash flow hedges[b]	—	—	—	—	—	6	—	—	—	6
Reclassification into earnings from cash flow hedges[c]	—	—	—	—	—	38	—	—	—	38
Minimum pension liability adjustment[d]	—	—	—	—	—	—	(1)	—	—	(1)
Other[f]	—	—	—	—	—	—	—	—	(15)	(15)
Total comprehensive income										1,994
Retirement of old Duke Energy shares	(927)	(10,399)	—	—	—	—	—	—	—	(10,399)
Issuance of new Duke Energy shares	927	1	10,398	—	—	—	—	—	—	10,399
Common stock issued in connection with Cinergy merger	313	—	8,993	—	—	—	—	—	—	8,993
Conversion of Cinergy options to Duke Energy options	—	—	59	—	—	—	—	—	—	59
Dividend reinvestment and employee benefits	6	22	172	—	—	—	—	—	—	194
Stock repurchase	(17)	(69)	(431)	—	—	—	—	—	—	(500)
Common stock dividends	—	—	—	(1,488)	—	—	—	—	—	(1,488)
Conversion of debt to equity	27	—	632	—	—	—	—	—	—	632
Tax benefit due to conversion of debt to equity	—	—	34	—	—	—	—	—	—	34
Adjustment due to SFAS No. 158 adoption[e]	—	—	—	—	—	—	61	(311)	—	(250)
Other capital stock transactions, net	—	—	(3)	—	—	—	—	—	—	(3)
Balance December 31, 2006	**1,257**	**$ 1**	**$19,854**	**$ 5,652**	**$949**	**$ (43)**	**$ —**	**$(311)**	**$ 2**	**$ 26,102**

[a] Foreign currency translation adjustments, net of $52 tax benefit in 2005. The 2005 tax benefit related to the settled net investment hedges (see Note 8 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K). Substantially all of the 2005 tax benefit is a correction of an immaterial accounting error related to prior periods.
[b] Net unrealized gains on cash flow hedges, net of $3 tax expense in 2006, $233 tax expense in 2005, and $170 tax expense in 2004.
[c] Reclassification into earnings from cash flow hedges, net of $13 tax expense in 2006, $383 tax benefit in 2005, and $45 tax benefit in 2004. Reclassification into earnings from cash flow hedges in 2005, is due primarily to the recognition of Duke Energy North America's (DENA) unrealized net gains related to hedges on forecasted transactions which will no longer occur as a result of the sale to LS Power of substantially all of DENA's assets and contracts outside of the Midwestern United States and certain contractual positions related to the Midwestern assets (see Notes 8 and 13 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K).
[d] Minimum pension liability adjustment, net of $0 tax benefit in 2006, $218 tax expense in 2005, and $18 tax expense in 2004.
[e] Adjustment due to SFAS No. 158 adoption, net of $164 tax benefit in 2006. Excludes $596 recorded as a regulatory asset (see Note 22 to the Consolidated Financial Statements in Duke Energy's 2006 Form 10-K).
[f] Net of $9 tax benefit in 2006, and $10 tax expense in 2005.

See Notes to Consolidated Financial Statements in Duke Energy's 2006 Form 10-K.


WILLIAM BARNET III


G. ALEX BERNHARDT SR.


MICHAEL G. BROWNING


PHILLIP R. COX


ANN MAYNARD GRAY


JAMES H. HANCE JR.


JAMES T. RHODES


JAMES E. ROGERS


MARY L. SCHAPIRO


DUDLEY S. TAFT

BOARD OF DIRECTORS

William Barnet III
Chairman, President and CEO, The Barnet Co. Inc.;
Chair, Finance and Risk Management Committee;
Member, Nuclear Oversight Committee
Barnet joined Duke Energy's board in 2005. He has been mayor of Spartanburg, S.C., since 2002. He serves on the board of directors of Bank of America and is a trustee of the Duke Endowment. Barnet was named to the South Carolina Business Hall of Fame in 2004.

G. Alex Bernhardt Sr.
Chairman and CEO, Bernhardt Furniture Co.;
Member, Audit and Nuclear Oversight Committees
Bernhardt joined Duke Energy's board in 1991. Besides leading the family business in Lenoir, N.C., he serves on the board of directors of Communities In Schools. He is director emeritus and past president of the American Furniture Manufacturers Association and past president of the International Home Furnishings Marketing Association.

Michael G. Browning
President and Chairman of the Board, Browning Investments Inc.;
Member, Compensation, Corporate Governance, and Finance and Risk Management Committees
Browning joined Cinergy's board in 1994. He is a former director of PSI Energy. He is a member of the boards of directors of the Indianapolis Convention & Visitors Association and the Indianapolis Museum of Art. He serves on the St. Vincent Hospital and Health Care Center advisory board and on the Indiana Public Officers Compensation Commission.

Phillip R. Cox
President and CEO, Cox Financial Corp.;
Chair, Audit Committee
Cox became a Cinergy director in 1994. He is a former director of Cincinnati Gas & Electric. He is chairman of the board of Cincinnati Bell. He is a board member of Touchstone Mutual Funds, The Timken Company and Diebold Inc. He also serves on the boards of the Cincinnati Business Committee and the University of Cincinnati.

Ann Maynard Gray
Former President, Diversified Publishing Group of ABC Inc.;
Lead Director; Chair, Corporate Governance Committee;
Member, Compensation, and Finance and Risk Management Committees
Gray became a Duke Energy director in 1994. She has held a number of senior positions with American Broadcasting Companies, including senior vice president of finance, treasurer and vice president of planning. She serves on the boards of the Phoenix Companies and Elan Corp. plc, and she is a past member of the board of trustees of J.P. Morgan Funds.

James H. Hance Jr.
Retired Vice Chairman, Chief Financial Officer and Board Member, Bank of America;
Chair, Compensation Committee; Member, Finance and Risk Management Committee
Hance joined Duke Energy's board in 2005. A certified public accountant, he spent 17 years with Price Waterhouse. He serves on the boards of directors for Sprint Nextel Corp., Cousins Properties Inc. and Rayonier Corp. He is a trustee of Washington University and of Johnson & Wales University.

James T. Rhodes
Retired Chairman, President and CEO, Institute of Nuclear Power Operations (INPO);
Chair, Nuclear Oversight Committee; Member, Audit Committee
Rhodes became a director of Duke Energy in 2001. A former president and CEO of Virginia Power, he is a member of the Electric Power Research Institute's advisory council. Rhodes is a former board member of INPO, the Nuclear Energy Institute, Virginia Electric and Power Co., Dominion Resources Inc., Edison Electric Institute, the Southeastern Electric Exchange and NationsBank N.A.

James E. Rogers
Chairman, President and CEO, Duke Energy
Rogers became chairman of Duke Energy in 2007. He was chairman and CEO of Cinergy prior to its merger with Duke Energy. Rogers is chairman and serves on the Executive Committee of the Edison Electric Institute. He is a director of Fifth Third Bancorp and Cigna Corp. He is a member of the boards of directors of the Nuclear Energy Institute, the Institute of Nuclear Power Operations, the Alliance to Save Energy, the National Coal Council and the Nicholas Institute for Environmental Policy Solutions.

Mary L. Schapiro
Chairman and CEO, National Association of Securities Dealers (NASD);
Member, Audit and Corporate Governance Committees
Schapiro became a Cinergy director in 1999. She is a member of the board of governors of NASD, the world's largest private-sector securities regulator. Previously, as chairman of the Commodity Futures Trading Commission, she participated in the President's Working Group on Financial Markets. She also served as a commissioner on the Securities and Exchange Commission for six years. She currently serves on the board of directors of Kraft Foods Inc. and the board of trustees of Franklin and Marshall College.

Dudley S. Taft
President and CEO, Taft Broadcasting Co.;
Member, Compensation and Nuclear Oversight Committees
Taft served on Cinergy's board beginning in 1994 and was a director of Cincinnati Gas & Electric from 1985 until 1995. He serves on the boards of the Unifi Mutual Holding Co., Fifth Third Bancorp and Tribune Co. He is chairman of the Cincinnati Association for the Arts and a trustee of Boys and Girls Clubs of Greater Cincinnati.


HENRY B. BARRON JR.


PAUL H. BARRY


LYNN J. GOOD


DAVID L. HAUSER


JULIA S. JANSON


MARC E. MANLY


WILLIAM R. MCCOLLUM JR.


SANDRA P. MEYER


THOMAS C. O'CONNOR


CATHY S. ROCHE


CHRISTOPHER C. ROLFE


ELLEN T. RUFF


JIM L. STANLEY


R. SEAN TRAUSCHKE


B. KEITH TRENT


JAMES L. TURNER

EXECUTIVE MANAGEMENT

Henry B. Barron Jr.
Group Executive and Chief Nuclear Officer
Barron became Duke Energy's chief nuclear officer in 2004. He is responsible for the safe operation of the company's three nuclear generating stations. He joined Duke Power in 1972 as a nuclear power plant engineer.

Paul H. Barry
Senior Vice President and Chief Development Officer
Barry is responsible for all corporate development, mergers and acquisitions. He previously served as group executive and president of Duke Energy Americas, where his responsibilities included non-regulated generation and services, trading and marketing, and international operations.

Lynn J. Good
Senior Vice President and Treasurer
Good leads the treasury functions for the company, as well as insurance, market and credit risk management, and corporate financial planning and analysis. She previously served as executive vice president and chief financial officer for Cinergy.

David L. Hauser
Group Executive and Chief Financial Officer
Hauser became Duke Energy's CFO in 2004. He leads the financial function, which includes the controller's office, treasury, tax, risk management and insurance. Since Hauser joined Duke Power in 1973, he has held various leadership positions, including controller.

Julia S. Janson
Senior Vice President, Ethics and Compliance, and Corporate Secretary
Janson directs Duke Energy's ethics and compliance program and serves as corporate secretary. Until the recent merger, she was with Cinergy, where she was named corporate secretary in 2000, and chief compliance officer in 2004.

Marc E. Manly
Group Executive and Chief Legal Officer
Manly leads a group that comprises the legal department, internal audit services, the ethics and compliance office, and the corporate secretary. He served as Cinergy's executive vice president and chief legal officer from 2002 until Cinergy merged with Duke Energy.

William R. McCollum Jr.
Group Executive and Chief Regulated Generation Officer
McCollum is responsible for the company's regulated fossil fuel and hydroelectric power generation including portfolio optimization, engineering, construction, project management and procurement. He joined Duke Power as a nuclear power plant engineer in 1974.

Sandra P. Meyer
President, Duke Energy Ohio and Duke Energy Kentucky
Meyer leads Duke Energy's Ohio and Kentucky operations which serve more than 810,000 customers. She was formerly group vice president of customer service, sales and marketing for Duke Power.

Thomas C. O'Connor
Group Executive and President, Commercial Businesses
O'Connor is responsible for the Midwest non-regulated generation, Duke Energy International, Duke Energy Generation Services, the telecommunications businesses, the company's equity interest in Crescent Resources, and all corporate development and merger and acquisition activities.

Cathy S. Roche
Senior Vice President and Chief Communications Officer
Roche is responsible for directing and managing Duke Energy's communications with internal and external audiences, as well as executive communications, corporate publications, advertising, and brand management and strategy.

Christopher C. Rolfe
Group Executive and Chief Administrative Officer
Rolfe leads several of Duke Energy's corporate functions, including human resources, information technology and operations services. He previously served as group executive and chief human resources officer.

Ellen T. Ruff
President, Duke Energy Carolinas
Ruff leads Duke Energy's utility business in North Carolina and South Carolina, which serves more than 2.2 million customers. She was formerly group vice president of planning and external relations for Duke Power.

Jim L. Stanley
President, Duke Energy Indiana
Stanley leads Duke Energy's Indiana utility business, which serves more than 760,000 customers. He previously served as vice president of field operations for Duke Energy's Midwest service area.

R. Sean Trauschke
Vice President, Investor Relations
Trauschke is responsible for monitoring trends in investment markets and for maintaining key relationships with investors, financial analysts and financial institutions. He was formerly the company's vice president of risk management, chief risk officer and chief credit officer.

B. Keith Trent
Group Executive and Chief Strategy and Policy Officer
Trent is responsible for strategy, federal policy and government affairs, energy efficiency and technology initiatives, environmental health and safety policy, corporate communications, and sustainability and community affairs. He was formerly chief development officer and general counsel.

James L. Turner
Group Executive and President, U.S. Franchised Electric and Gas
Turner has overall profit and loss responsibility for the company's U.S. Franchised Electric and Gas business, which serves 3.9 million customers in five states. Prior to the merger of Duke Energy and Cinergy, Turner served as president of Cinergy

NON-GAAP FINANCIAL MEASURES

2006 AND 2005 ONGOING DILUTED EARNINGS PER SHARE ("EPS")

Duke Energy's 2006 Summary Annual Report references 2006 and 2005 ongoing diluted EPS of $1 81 and $1 73. respectively. Ongoing diluted EPS is a non-GAAP (generally accepted accounting principles) financial measure, as it represents diluted EPS from continuing operations plus the per-share effect of any discontinued operations from our Crescent Resources real estate development company ("Crescent") prior to the deconsolidation of Crescent in September 2006, adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The following is a reconciliation of reported diluted EPS from continuing operations to ongoing diluted EPS for 2006 and 2005:

	2006	2005
Diluted EPS from continuing operations, as reported	**$ 1.70**	$ 2.60
Diluted EPS from discontinued operations, as reported	**(0.13)**	(0.72)
Diluted EPS, as reported	**1.57**	1.88
Adjustments to reported EPS:		
Diluted EPS from discontinued operations excluding Crescent Resources, and cumulative effect of change in accounting principle	**0.13**	0.73
Diluted EPS impact of special items (see detail below)	**0.11**	(0.88)
Diluted EPS, ongoing	**$1.81**	**$1.73**

The following is the detail of the $(0 11) in special items impacting diluted EPS for 2006:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2006 Diluted EPS Impact
Natural Gas Transmission gain on contract settlement	$ 24	$ (8)	$ 0.01
Duke Energy portion of gain on Duke Energy Field Services' ("DEFS") asset sale	14	(5)	0.01
Costs to achieve the Cinergy merger	(128)	45	(0.07)
Costs to achieve the spinoff of Spectra Energy	(60)	7	(0.05)
Impairment of Campeche investment	(50)	—	(0.04)
Gain on sale of interest in Crescent	246	(124)	0.10
Gain related to the issuance of units of Natural Gas Transmission's Canadian income fund	15	(5)	0.01
Settlement reserves	(165)	58	(0.09)
Impairment of Bolivia investment	(28)	31	—
Tax adjustment	—	8	0.01
Total Diluted EPS impact			**$(0.11)**

The following is the detail of the $0.88 in special items impacting diluted EPS for 2005:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2005 Diluted EPS Impact
Gain on sale of TEPPCO GP (net of minority interest of $343 million)	$791	$(293)	$ 0.51
Gain on sale of TEPPCO LP units	97	(36)	0.06
Loss on de-designation of Field Services' hedges, net of settlements on 2005 positions	(23)	9	(0.01)
Additional liabilities related to mutual insurance companies	(28)	10	(0.02)
Gain on transfer of 19.7 percent interest in DEFS to ConocoPhillips	576	(213)	0.37
Impairment of Campeche investment	(20)	6	(0.01)
Initial and subsequent net mark-to-market gains on de-designating Southeast Duke Energy North America ("DENA") hedges	21	(8)	0.01
Loss on Southeast DENA contract termination	(75)	28	(0.04)
Tax adjustments	—	12	0.01
Total Diluted EPS impact			**$ 0.88**

PROCEEDS FROM CERTAIN SIGNIFICANT 2006 DISPOSITION TRANSACTIONS

Duke Energy's 2006 Summary Annual Report references the nearly $2 billion in after-tax proceeds raised from selling the commercial marketing and trading ("CMT") operations and effectively half of Crescent. The following represents the components of the after-tax proceeds from these transactions:

(In millions)	
Proceeds related to Creation of Crescent Joint Venture	
Net proceeds from issuance of debt by Crescent	$1,190
Proceeds received from sale of equity interest	415
Estimated income tax payments resulting from transaction	(135)
Reduction in reported cash due to deconsolidation of Crescent	(30)
Net after-tax proceeds	$1,440
Proceeds on Sale of CMT	
Net proceeds received (including working capital and base price)	$700
Estimated income tax payments resulting from transaction	(145)
Net after-tax proceeds	$555
Total combined net after-tax proceeds	**$1,995**

2007 EMPLOYEE INCENTIVE TARGET MEASURE

Duke Energy's 2006 Summary Annual Report references the company's 2007 employee incentive target. The EPS measure used for employee incentive bonuses is based on ongoing diluted EPS. Ongoing diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for ongoing diluted EPS is reported diluted EPS from continuing operations, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast any special items for any future periods.

ANTICIPATED ONGOING DILUTED EPS GROWTH PERCENTAGES

Duke Energy's 2006 Summary Annual Report references the company's anticipated growth in ongoing diluted EPS through the end of 2009. These growth percentages are based on anticipated ongoing diluted EPS. Ongoing diluted EPS is a non-GAAP financial measure, as it represents diluted EPS from continuing operations adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for ongoing diluted EPS is reported diluted EPS from continuing operations, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast any special items for any future periods.

FORECASTED 2007 ONGOING SEGMENT AND TOTAL SEGMENT EBIT

Duke Energy's 2006 Summary Annual Report includes a discussion of forecasted 2007 ongoing EBIT for each of Duke Energy's reportable segments as a percentage of forecasted 2007 ongoing total segment EBIT. Forecasted 2007 ongoing segment and total segment EBIT amounts are non-GAAP financial measures, as they reflect segment and total segment EBIT, adjusted for the impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for forecasted ongoing segment EBIT is reported segment EBIT from continuing operations, which includes the impact of special items. The most directly comparable GAAP measure for ongoing total segment EBIT is reported total segment EBIT, which includes the impact of special items. Due to the forward-looking nature of these non-GAAP financial measures for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures is not available at this time, as management is unable to forecast any special items for any future periods.

INVESTOR INFORMATION

Annual Meeting
The 2007 Annual Meeting of Duke Energy Shareholders will be:
Date: Thursday, May 10, 2007
Time: 10 a.m.
Place: O.J. Miller Auditorium,
Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services
Shareholders may call (800) 488-3853 or (704) 382-3853 with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Additionally, registered users of DUK-Online, our online account management service, may access their accounts through the Internet.

Send written requests to:
Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005

For electronic correspondence, visit www.duke-energy.com/contactIR.

Stock Exchange Listing
Duke Energy's common stock is listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Addresses
Corporate home page:
www.duke-energy.com
Investor Relations:
www.duke-energy.com/investors

InvestorDirect Choice Plan
The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available. The plan also provides for full reinvestment, direct deposit or cash payment of dividends. Additionally, participants may register for DUK-Online, our online account management tool.

Financial Publications
Duke Energy's current annual report, SEC Form 10-K and related financial publications can be found on our Web site at www.duke-energy.com/investors. Printed copies are also available free of charge upon request.

Electronic Delivery
As part of our commitment to sustainability leadership, we are again offering to make a $1 donation to The Nature Conservancy for every shareholder who signs up for electronic delivery of our annual report, proxy statement and our other financial information. Currently, more than 80,000 of you have chosen electronic delivery, and we intend to make an equivalent donation in dollars to The Nature Conservancy. This effort helps preserve our natural resources and significantly reduces our printing and mailing costs.

You only need to sign up once. To enroll in electronic delivery, go to https://www.icsdelivery.com/duk/index.html. To learn more about the work of The Nature Conservancy, visit http://www.nature.org.

Duplicate Mailings
If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar
Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common stock issues.

Dividend Payment
Duke Energy has paid quarterly cash dividends on its common stock for 80 consecutive years. For the rest of 2007, dividends on common stock are expected to be paid, subject to declaration by the Board of Directors, on June 18, Sept. 17 and Dec. 17, 2007.

Bond Trustee
If you have questions regarding your bond account, call (800) 275-2048, or write to:
The Bank of New York
Global Trust Services
101 Barclay Street
New York, NY 10286

NYSE CEO Certification
Duke Energy Corporation has filed the certification of its chief executive officer and chief financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for the year ended December 31, 2006. In November 2006, Duke Energy Corporation's chief executive officer, as required by Section 303A.12(a) of the NYSE Listed Company Manual, certified to the NYSE that he was not aware of any violation by Duke Energy Corporation of the NYSE's corporate governance listing standards.

Send Us Feedback
We welcome your opinion on Duke Energy's 2006 Summary Annual Report. Please visit www.duke-energy.com/investors, where you can view the online Annual Report and provide feedback on both the print and online versions. Or contact Investor Relations directly.

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Sustainability At Duke Energy

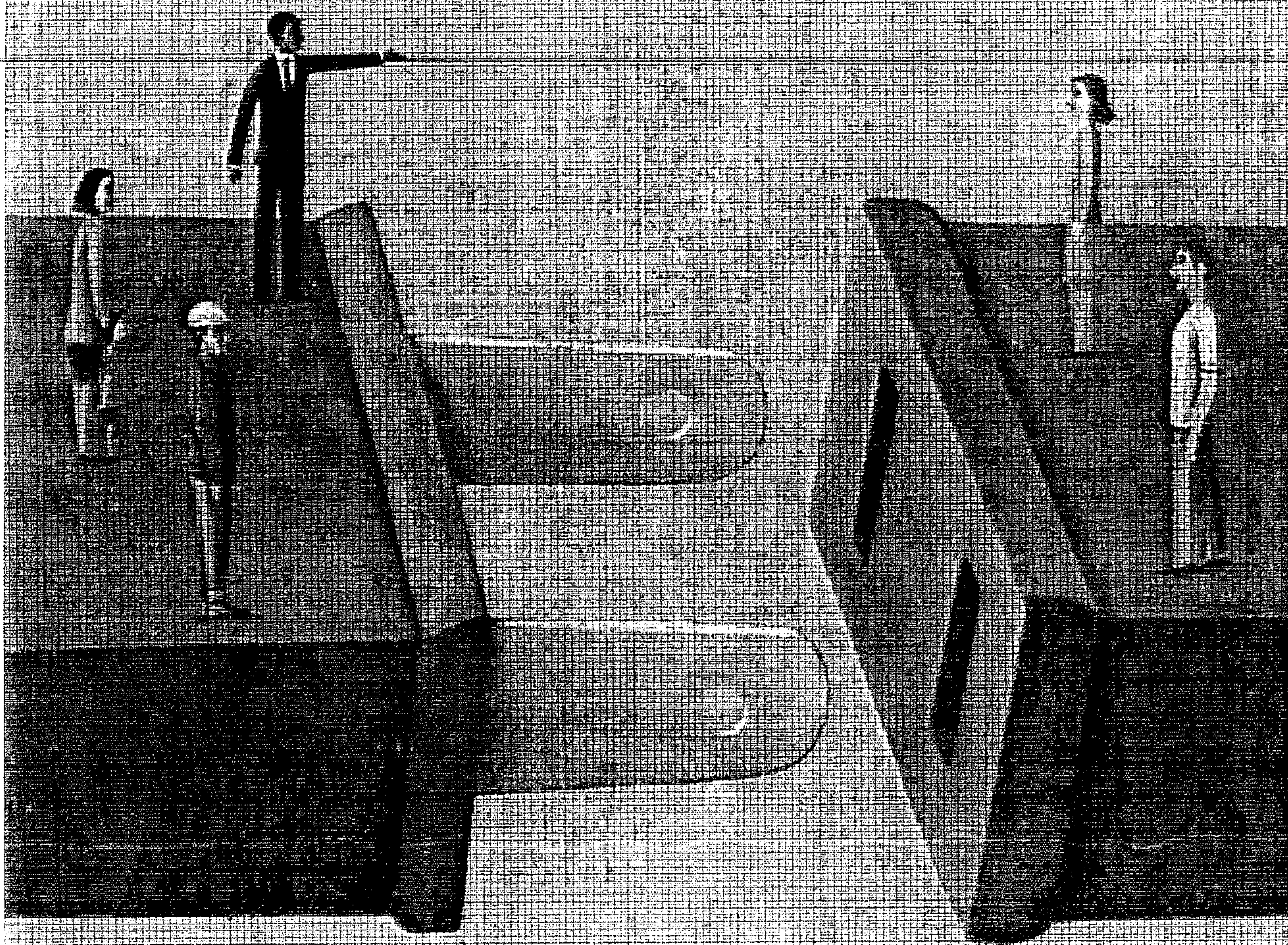
Mixed Sources

FSC

Duke Energy

2007 SUMMARY ANNUAL REPORT

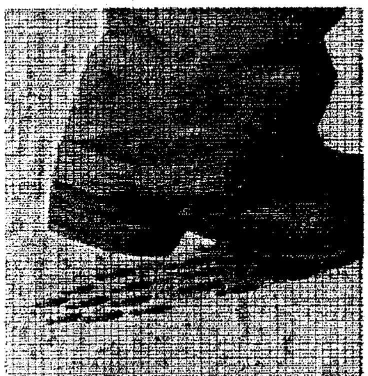
Building bridges for a low-carbon future



In 2007, we provided energy when our customers needed it, made plans to build new plants to meet growing demand, developed a new way to promote energy efficiency and continued to confront our industry's biggest challenge — global climate change. As one of the largest emitters of carbon dioxide in the world, we believe we have the responsibility to lead in bridging the gap between today's high-carbon economy and a low-carbon future. This report examines the bridges we are building to reduce our carbon footprint to benefit our current and future stakeholders.

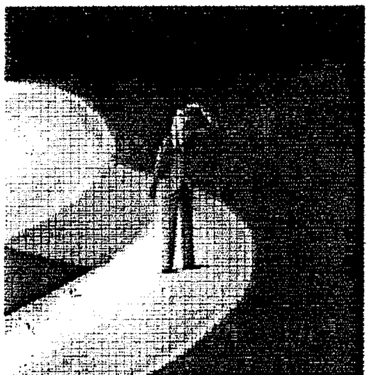
CONTENTS:

BUILDING BRIDGES TO A LOW-CARBON FUTURE:



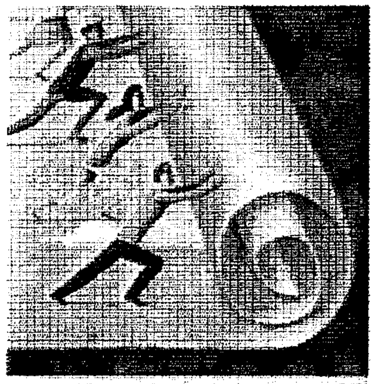
Where we are now 10

We are the third largest emitter of carbon dioxide (CO_2) in the United States — emitting more than 100 million tons last year. We've significantly reduced our non-carbon emissions over the last 20 years and with the right technologies, we believe we can do the same with CO_2. We are working to find solutions to this challenge that will protect and benefit our stakeholders.



Where we are going 12

We are assessing what it would take to cut our CO_2 emissions in half — to approximately 50 million tons — by 2030 and the implications of such an effort. By then, we will likely have replaced our oldest coal-fired power plants with advanced cleaner-coal and other technologies, including nuclear power, natural gas, renewable energy and greater use of energy efficiency.



How we will get there 14

We are taking five major steps to build bridges to a low-carbon future. We're shaping public policy, pursuing new technology, building projects and talent, balancing diverse interests and taking a long view so we can continue to create value for our stakeholders in the future.

For more information about our sustainability activities and environmental progress, please see the Duke Energy 2007|2008 Sustainability Report on the company Web site: www.duke-energy.com

2007 Financial Highlights[a]

(In millions, except per-share amounts)	**2007**	2006	2005	2004	2003[c]
Statement of Operations					
Total operating revenues	**$12,720**	$10,607	$ 6,906	$ 6,357	$ 6,006
Total operating expenses	**10,222**	9,210	5,586	5,074	6,550
Gains on sales of investments in commercial and multi-family real estate	**—**	201	191	192	84
(Losses) gains on sales of other assets and other, net	**(5)**	223	(55)	(435)	(202)
Operating income (loss)	**2,493**	1,821	1,456	1,040	(662)
Total other income and expenses	**428**	354	217	180	326
Interest expense	**685**	632	381	425	431
Minority interest expense (benefit)	**2**	13	24	(15)	(79)
Income (loss) from continuing operations before income taxes	**2,234**	1,530	1,268	810	(688)
Income tax expense (benefit) from continuing operations	**712**	450	375	192	(288)
Income (loss) from continuing operations	**1,522**	1,080	893	618	(400)
(Loss) income from discontinued operations, net of tax	**(22)**	783	935	872	(761)
Income (loss) before cumulative effect of change in accounting principle	**1,500**	1,863	1,828	1,490	(1,161)
Cumulative effect of change in accounting principle, net of tax and minority interest	**—**	—	(4)	—	(162)
Net income (loss)	**1,500**	1,863	1,824	1,490	(1,323)
Dividends and premiums on redemption of preferred and preference stock	**—**	—	12	9	15
Earnings (loss) available for common stockholders	**$ 1,500**	$ 1,863	$ 1,812	$ 1,481	$ (1,338)
Ratio of Earnings to Fixed Charges	**3.7**	2.6	2.4	1.6	—[b]
Common Stock Data					
Shares of common stock outstanding[d]					
Year-end	**1,262**	1,257	928	957	911
Weighted average — basic	**1,260**	1,170	934	931	903
Weighted average — diluted	**1,266**	1,188	970	966	904
Earnings (loss) per share (from continuing operations)					
Basic	**$ 1.21**	$ 0.92	$ 0.94	$ 0.66	$ (0.44)
Diluted	**1.20**	0.91	0.92	0.64	(0.44)
(Loss) earnings per share (from discontinued operations)					
Basic	**$ (0.02)**	$ 0.67	$ 1.00	$ 0.94	$ (0.86)
Diluted	**(0.02)**	0.66	0.96	0.90	(0.86)
Earnings (loss) per share (before cumulative effect of change in accounting principle)					
Basic	**$ 1.19**	$ 1.59	$ 1.94	$ 1.59	$ (1.30)
Diluted	**1.18**	1.57	1.88	1.54	(1.30)
Earnings (loss) per share					
Basic	**$ 1.19**	$ 1.59	$ 1.94	$ 1.59	$ (1.48)
Diluted	**1.18**	1.57	1.88	1.54	(1.48)
Dividends per share[e]	**0.86**	1.26	1.17	1.10	1.10
Balance Sheet					
Total assets	**$49,704**	$68,700	$54,723	$55,770	$57,485
Long-term debt including capital leases, less current maturities	**$ 9,498**	$18,118	$14,547	$16,932	$20,622

a Significant transactions reflected in the results above include: 2007 spinoff of the natural gas businesses (see Note 1 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Summary of Significant Accounting Policies"), 2006 merger with Cinergy (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Acquisitions and Dispositions"), 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Acquisitions and Dispositions"), 2005 DENA disposition (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Discontinued Operations and Assets Held for Sale"), 2005 deconsolidation of DCP Midstream effective July 1, 2005 (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Discontinued Operations and Assets Held for Sale"), 2005 DCP Midstream sale of TEPPCO (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Discontinued Operations and Assets Held for Sale") and 2004 sale of the former DENA Southeast plants.

b Earnings were inadequate to cover fixed charges by $746 million for the year ended December 31, 2003.

c As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force (EITF) 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). In accordance with the transition guidance for these standards, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles.

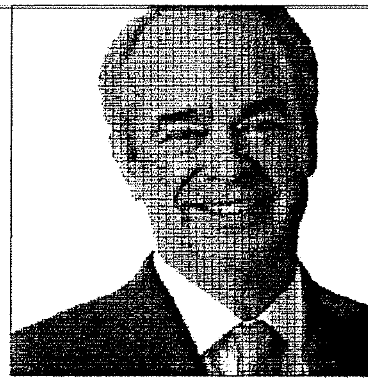
d 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Acquisitions and Dispositions").

e 2007 decrease due to the spinoff of the natural gas businesses to shareholders on January 2, 2007 as dividends subsequent to the spinoff were split proportionately between Duke Energy and Spectra Energy such that the sum of the dividends of the two stand-alone companies approximates the former total dividend of Duke Energy prior to the spinoff.

See Notes to Consolidated Financial Statements in Duke Energy's 2007 Form 10-K.

Chairman's Letter to Stakeholders

Dear fellow investors, customers, employees and all who have an interest in our success — our partners, suppliers, policymakers, regulators and communities:



JAMES E. ROGERS
Chairman, President and Chief Executive Officer

We believe that all companies should have great aspirations. At Duke Energy, we have two aspirations that guide our planning and serve as a bridge to the future: (1) Modernize and decarbonize our generation fleet, and (2) Help make the communities we serve the most energy efficient in the world.

These aspirations are grounded in our commitments to provide our customers with clean, affordable and reliable electric and gas services, and to allocate capital over the long term to grow earnings for investors.

Our aspirations are also shaped by the ongoing debate over how to address global climate change. They are action-based. They recognize our intent to ensure that rules limiting greenhouse gas (GHG) emissions will fairly balance the needs of all of our stakeholders.

In this letter I will describe how we are building bridges to a low-carbon future. My confidence in our ability to succeed is based on the dedication of our people. Their hard work and perseverance was evident in our 2007 results.

"Most of the electricity generated in this country is fueled by four natural resources: coal, uranium, natural gas and water. We include a fifth fuel — energy efficiency. By helping our customers use power more efficiently, we can help them save money and reduce the need for new power plants."

2007 — A STRONG, PRODUCTIVE YEAR

Last year, we faced weather-related challenges of record-setting summer heat throughout our service territory and a persistent drought in the Carolinas. We continued to make progress in integrating our 2006 merger with Cinergy, and we completed the spinoff of our natural gas businesses. The people of Duke Energy met these challenges while achieving solid results in customer service and operations.

- ***We increased earnings per share and total return:*** Ongoing diluted earnings per share of $1.24 in 2007 exceeded 2006 ongoing diluted earnings per share of $0.99. Duke Energy's total shareholder return (TSR) — a combination of the change in stock price plus dividends paid out — was more than 9 percent in 2007. This beat the S&P 500 index TSR of 5.5 percent.
- ***We achieved constructive legislative and regulatory outcomes:*** We received approvals to build two new advanced coal plants in Indiana and North Carolina. Thanks to the diligent work of our teams, we received final air permits for both in January 2008. We helped pass comprehensive energy legislation in North Carolina and South Carolina. The legislation enables the more timely recovery of certain operating costs, such as the reagents and chemicals we use in our environmental equipment on our coal plants. And it allows more timely recovery of the financing costs associated with the construction of new baseload generation. In North Carolina, we settled our rate case, which reduced industrial, commercial and residential rates without a material impact on 2008 earnings. In Ohio, we continue to support legislation that will ensure future rate certainty for our customers in that state.
- ***We grew our renewable energy portfolio:*** Our Commercial Businesses acquired 1,000 megawatts of wind power assets planned or under development in the western and southwestern United States. We also began construction of two small hydroelectric power plants in Brazil.
- ***We dedicated ourselves to customer service and economic development:*** We achieved improvements in our key internal satisfaction measures for all customer classes. Economic development efforts helped stimulate new capital investments and new jobs in our five-state service territory.
- ***We met productivity targets:*** Our nuclear and coal plants performed superbly when we needed them the most. Our nuclear fleet had its third-best year ever for capacity. Despite the drought, careful management of our coal and hydro units enabled us to successfully meet our customers' record demand for both peak and baseload power.

BUILDING BRIDGES TO A LOW-CARBON FUTURE

In 2008, we'll continue to focus on delivering results for both customers and investors in our basic business. At the same time, we will continue to chip away at the most difficult challenge in the history of our industry: global climate change.

Demand for electricity is growing locally and globally. Each year, Duke Energy alone is adding approximately 40,000 to 60,000 new customers in the Carolinas, and 11,000 to 16,000 new customers in the Midwest. This means we will need more than 6,000 megawatts of new generating capacity by 2012. According to the U.S. Department of Energy, nationwide power demand will grow approximately 35 percent by 2030.

At the same time, evidence is growing that carbon dioxide (CO_2) released into the atmosphere from burning fossil fuels is creating conditions that could change our way of life. Scientists know climate change is a problem, yet they aren't able to accurately predict its full scope. I leave the science to the scientists, but as an energy company CEO, I have a responsibility to protect our assets against such risks — to meet the need for power, without risking our children's futures.

We must plan ahead. It takes five or more years to build a new baseload coal plant, and 10 to 15 years to build a new nuclear plant. To ensure we can deliver reliable and affordable power to our customers, we have to start now. But today, we lack advanced technologies that can achieve this seemingly impossible dual mission: high growth and low carbon. Consequently, we have developed a multi-pronged strategy to bridge the gap between our current high-carbon economy and a low-carbon future.

Let me explain in this letter how the people of Duke Energy are building four bridges: (1) from "production" (making watts) to "efficiency" (saving watts); (2) from conventional to unconventional generating technologies; (3) spanning investor expectations and new regulatory rules; and (4) from following the status quo to leading with forward-looking policies.

THE FIRST BRIDGE: FROM PRODUCTION (MAKING WATTS) TO EFFICIENCY (SAVING WATTS)

Most of the electricity generated in this country is fueled by four natural resources: coal, uranium, natural gas and water. We include a fifth fuel — energy efficiency. By helping our customers use power more efficiently, we can help them save money and reduce the need for new power plants. In aggregate, energy efficiency investments are the least expensive and most environmentally benign source of energy for our customers.

Why isn't more being done to promote energy efficiency? As co-chair of the National Action Plan on Energy Efficiency and the Alliance to Save Energy, I reviewed state regulatory plans for energy efficiency. We found that many utilities don't invest in such programs, because the current regulatory framework is biased against investments in energy efficiency in favor of putting steel in the ground. Our goal is to change that regulatory paradigm so that earnings from energy efficiency are on a par with earnings from investments in new power plants.

In 2007, we introduced Duke Energy's energy efficiency plan, which is designed to set investment returns for the costs and savings of energy efficiency programs. Customers would benefit because they would pay 10 to 15 percent less for energy efficiency than for a new power plant. We filed for regulatory approval of this plan in Indiana, North Carolina and South Carolina. As I was writing this letter, we reached

2007 MAJOR ACHIEVEMENTS

FIRST QUARTER

- Completed the spinoff of Spectra Energy.
- Received approval to build an 800-megawatt advanced coal-fired unit at our Cliffside station in western North Carolina (final air permit received in January 2008).

SECOND QUARTER

- Issued first Sustainability Report.
- Filed energy efficiency plan in North Carolina.
- Helped pass comprehensive energy legislation in South Carolina that provides for the recovery of new nuclear plant financing costs during the construction phase and allows recovery of costs of certain reagents used in emission removal.
- Acquired 1,000 megawatts of wind energy assets under development in the western and southwestern United States.

THIRD QUARTER

- Met customers' demand for electricity during record-setting summer heat throughout the service territory and record-setting drought in the Carolinas.
- Helped pass comprehensive energy legislation in North Carolina that enables the recovery of new plant financing costs during the construction phase and allows recovery of costs of certain reagents used in emission removal. The legislation includes a workable renewable energy and energy efficiency portfolio standard.
- Filed energy efficiency plan in South Carolina.

FOURTH QUARTER

- Filed energy efficiency plan in Indiana.
- Received remand order affirming the Ohio rate stabilization plan. The ruling maintains the current price and provides for the continuation of existing rate components.
- Received approval to build a 630-megawatt cleaner-coal integrated gasification combined cycle (IGCC) power plant in southwestern Indiana (final air permit received in January 2008).
- Settled rate case in North Carolina, which reduced industrial, commercial and residential rates with no material impact on 2008 earnings.
- Filed applications with state regulators for certificates of public convenience and necessity to add two 620-megawatt combined cycle, natural gas-fired units at two existing power plants in North Carolina.
- Submitted a combined construction and operating license application to the U.S. Nuclear Regulatory Commission for the proposed 2,234-megawatt Lee Nuclear Station in Cherokee County, S.C.
- 2007 ongoing diluted earnings per share of $1.24 exceeded 2006 ongoing diluted earnings per share of $0.99.

FULL YEAR

- Continued push for federal cap-and-trade legislation limiting greenhouse gas emissions.

"In aggregate, energy efficiency investments are the least expensive and most environmentally benign source of energy for our customers."

a partial settlement in South Carolina for our plan. We expect to file similar plans in Ohio and Kentucky in 2008.

We were pleased that in February 2008, the Alliance to Save Energy, the American Council for an Energy-Efficient Economy and the Energy Future Coalition endorsed our energy efficiency model as "an innovative and promising new direction for the company and its customers."

Building the smart grid — the backbone of reliability

In 2007, we began installing smart meters in Charlotte, N.C., Cincinnati, Ohio, and northwestern South Carolina. Turning analog meters into digital or smart meters enables real-time communication between our power grids and our customers' homes. This will help our customers monitor and manage their power consumption. We have about 7,500 smart meters in place today. With appropriate regulatory recovery, we expect to install an additional 60,000 by the end of 2009.

Over the next five years, we plan to spend about $1 billion to digitize our distribution system. These improvements will help us better balance supply and demand, pinpoint trouble sooner, and restore outages faster or avoid them altogether.

THE SECOND BRIDGE: FROM CONVENTIONAL TO UNCONVENTIONAL GENERATING TECHNOLOGIES

Our energy efficiency focus is vital to providing reliable and cost-effective electricity in the future. But efficiency alone cannot satisfy growing demand and at the same time reduce our CO_2 emissions. We must do more. Instead of looking for a "silver bullet" strategy, we are taking a "silver buckshot" approach. Using new technologies, we plan to build an efficient generation portfolio powered by coal, nuclear, natural gas and renewables. Over the next five years, we plan to invest approximately $23 billion (almost equal to our current market cap) to make our entire system more efficient, retire inefficient plants and increase renewable generation.

Advanced coal technologies

When people ask, "How can a company committed to a low-carbon future continue to build new coal plants?" I remind them of these key facts: Today, coal accounts for about 50 percent of our nation's total electric generation. In the United States, Duke Energy's system is about 70 percent coal. We burn coal today because it is the most abundant and economical fuel available for large-scale reliable power generation. We are finding ways to use coal more efficiently and cleanly.

Indiana regulators approved our four-year plan to build a cleaner-coal integrated gasification combined cycle (IGCC) plant. The 630-megawatt Edwardsport plant is currently expected to cost approximately $2 billion. To encourage this new technology, the project will receive $460 million in local, state and federal tax incentives and credits.

The new plant will be one of the cleanest and most efficient coal-fired power plants in the world. It will emit less sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulates than the plant it replaces — while providing more than 10 times the power of the existing plant. The current 160-megawatt plant emits about 13,000 tons of SO_2, NO_x and particulates annually and runs about 30 percent of the time. By comparison, a new 630-megawatt IGCC plant running 100 percent of the time will emit about 2,900 tons of the same pollutants. It will also use about 11 million gallons of water a day, compared to the current plant, which uses almost 190 million gallons daily.

Eventually we hope to be able to capture and permanently store the CO_2 emitted from this plant in nearby underground formations, keeping it out of the atmosphere.

North Carolina regulators approved our plan to build a new 800-megawatt unit at our Cliffside Steam Station. At a cost of approximately $2.4 billion, this plant will use supercritical coal-combustion technology, which is 30 percent more efficient than the units it will replace. As a result, it will generate twice the amount of electricity of the existing plant with only one-seventh of the SO_2, one-third of the NO_x and one-half the mercury emissions. The new unit's air permit includes limits on SO_2 and NO_x emissions that are stricter than current state and federal rules. The state's mercury limits are already more stringent than federal rules. The project will receive $125 million in federal clean-coal tax credits.

We also agreed to implement a unique CO_2 mitigation plan for Cliffside. As part of that plan, we will retire the plant's four older coal units by 2012 and shut down 800 megawatts of other older coal units by 2018. In addition, we agreed to invest 1 percent or approximately $50 million of our North Carolina revenues from our regulated operations each year in energy efficiency, pending appropriate regulatory approval.

OUR MISSION, OUR VALUES

Our Mission

At Duke Energy, we make people's lives better by providing gas and electric services in a sustainable way. This requires us to constantly look for ways to improve, to grow and to reduce our impact on the environment.

Our Values

- ***Caring*** — We look out for each other. We strive to make the environment and communities around us better places to live.
- ***Integrity*** — We do the right thing. We honor our commitments. We admit when we're wrong.
- ***Openness*** — We're open to change and to new ideas from our co-workers, customers and other stakeholders. We explore ways to grow our business and make it better.
- ***Passion*** — We're passionate about what we do. We strive for excellence. We take personal accountability for our actions.
- ***Respect*** — We value diverse talents, perspectives and experiences. We treat others the way we want to be treated.
- ***Safety*** — We put safety first in all we do.

Natural gas

Natural gas emits less CO_2 than coal, but it is more expensive — so we use it judiciously in our portfolio. We filed with our regulators to build two 620-megawatt gas-fired units, one each at our Buck and Dan River steam stations in North Carolina. Last year, we purchased nearly 1,300 megawatts of gas-fired generation in the Midwest and North Carolina, adding to our existing gas assets.

Non-fossil fuel: nuclear and renewable energy

Today, approximately 28 percent of the power we generate in the United States comes from zero CO_2-emitting nuclear and renewable energy — about 5,000 megawatts of nuclear capacity and about 3,200 megawatts of hydroelectric capacity. We also have more than 3,100 megawatts of hydroelectric capacity in South America.

To reduce CO_2 emissions and meet demand growth, nuclear power must play an even larger role in our portfolio. In December, we filed an application with the Nuclear Regulatory Commission for a combined construction and operating license for our proposed two-unit, 2,234-megawatt Lee Nuclear Station in South Carolina. We also filed with South Carolina regulators to invest and recover up to $230 million in the plant's upfront development costs. We saw similar cost recovery assurance legislation pass in North Carolina. Assuming timely regulatory approvals, we would anticipate unit 1 coming on line in 2018.

We will also increase our use of renewable energy, by adding wind, solar and biomass to our hydroelectric capacity. We will add up to 200 megawatts from renewable sources to serve our Indiana customers, and we are purchasing renewable energy capacity to supply our North Carolina customers starting in 2012. As noted earlier, our nonregulated business is also building a renewable energy portfolio. When completed, these projects will sell wholesale power to other utilities. We expect the first 240 megawatts of these nonregulated assets to come on line in 2008 and 2009.

THE THIRD BRIDGE: SPANNING INVESTOR EXPECTATIONS AND NEW REGULATORY RULES

During the 1970s and 1980s, the industry invested trillions of dollars to build new baseload generation. The result was a sobering demonstration of the limitations of traditional rate-of-return regulation — for both customers and investors. This construction binge resulted in rate shocks for customers, cost overruns, the cancellation of half-finished plants and ultimately red ink for shareholders.

In the 1990s, we turned to the deregulation of power markets, relying on market signals to build new generation cost-effectively. But these experiments produced other undesirable outcomes: overbuilding in premium fuels such as natural gas and the under-recovery of true investment costs.

The lessons are clear to customers, investors, regulators and policymakers. We need new rules based on what we learned from both building eras. Customers and investors can both benefit when regulators reduce the time between when we invest and when we start recovering our investments.

"As the third largest emitter of CO_2 in the United States, I believe we have a responsibility to provide policy leadership. We must imagine a low-carbon future for our grandchildren and act to lower CO_2 emissions now. Achieving a low-carbon future will require rigorous engineering solutions, continuing technological discoveries, the political will to bridge local interests and global needs, and leaps of imagination."

In 2007, South Carolina passed comprehensive energy legislation that includes provisions allowing recovery of new nuclear plant financing costs during the construction phase. Similarly, North Carolina lawmakers passed legislation that allows us to seek plant financing costs through a rate case. This legislation enables us to synchronize capital spending and rate cases associated with our major investments. The North Carolina law also provided a workable renewable energy and energy efficiency portfolio standard requiring investor-owned utilities to supply 12.5 percent of their power from renewable energy sources by 2021.

This far-thinking leadership will allow us to build new plants so we can deliver reliable and affordable service to our customers while reducing the risk of regulatory lag.

Our strong balance sheet allows us to fund our ambitious five-year building program without issuing public equity. Beginning in 2010, we expect to raise equity of about $200 million per year through our dividend reinvestment and internal benefit programs.

THE FOURTH BRIDGE: FROM FOLLOWING THE STATUS QUO TO LEADING WITH FORWARD-LOOKING POLICIES

I've described actions we are taking in our service territory to meet our growing demand for power and reduce our carbon footprint. With these steps, we will achieve our aspirations of modernizing and decarbonizing our fleet and making our communities more energy efficient.

But we must do more. As the third largest emitter of CO_2 in the United States, I believe we have a responsibility to provide policy leadership. We must imagine a low-carbon future for our grandchildren and act to lower CO_2 emissions now. Achieving a low-carbon future will require rigorous engineering solutions, continuing technological discoveries, the political will to bridge local interests and global needs, and leaps of imagination.

In 2007, we worked to win Congressional support of cap-and-trade rules to control GHG emissions, so that all businesses can calculate the investment needed to reduce their carbon footprints. We advocated for legislation that treats all industries and regions of the nation fairly and ensures that utility customers in high coal-using states aren't penalized. We believe a cap-and-trade approach is the fairest and most equitable and practical way to achieve a 60 to 80 percent reduction in our nation's GHG emissions by 2050.

We also need new ways to fund research, development and deployment of CO_2-reducing technologies. Without such funding, we won't make it across the bridge to a low-carbon future.

More business, political and community leaders are stepping forward to cross that bridge. They're not waiting for others to act. Such leaders are also emerging in our company. They and their colleagues know it's easier not to rock the boat. Yet they've chosen to act and to take personal responsibility for their results. They've chosen to lead with integrity, discipline, vision and compassion — and help prepare and develop our workforce for the future.

During the next five years, we expect almost a third of that workforce to retire. This presents both a recruitment challenge and a great opportunity to grow talent within the company. One of my team's top priorities is development of a highly talented workforce that has the skill and the will to position us for a low-carbon future.

FOCUSED ON GROWTH

Based on current assumptions, we expect to grow ongoing diluted earnings at 5 to 7 percent compounded annually through 2012. We've set our 2008 employee incentive target at $1.27, based on ongoing diluted earnings per share. Our growth objectives are supported by our commitment to balance the needs of our stakeholders, including future generations.

Our many accomplishments this past year were possible because of the diligence, hard work and imagination of the people of Duke Energy. I thank them on your behalf, and mine.

The catalysts to increase future earnings will be continuing cost management, execution on our investment-recovery strategy and steady organic growth. This represents a strong value proposition for our investors, and one that allows us to honor commitments to all of our stakeholders.

We will focus on these priorities as we continue to build bridges to a low-carbon future. I look forward to working together with you to achieve that goal.

James E. Rogers

JAMES E. ROGERS
Chairman, President and Chief Executive Officer

March 7, 2008

Leadership on Climate Disclosure

Investors, customers and other stakeholders need to know the risks and opportunities the company will face in a world of tightening greenhouse gas constraints. They also want to know what the company is doing to position itself for success in a low-carbon future.

As part of its commitment to transparency, Duke Energy has been reporting its carbon dioxide (CO_2) emissions to the U.S. Department of Energy and to the U.S. Environmental Protection Agency since 1995. For the past five years, the company has also participated in the Carbon Disclosure Project (CDP). The CDP is an independent organization that works with shareholders and participating companies who voluntarily share their assessment of the business risks and opportunities they face due to climate change and the associated regulatory requirements. Duke Energy's current CDP report can be found at www.cdproject.net and on the company Web site at www.duke-energy.com/environment/reports/carbon-disclosure-project.asp.

Duke Energy's SEC Form 10-K for 2007 included a detailed assessment of the climate policy debate in Washington and potential costs customers could see under specific legislative proposals. (This form can also be accessed on the company Web site.) The company pointed out that compliance costs will be highly dependent on allowance prices, and will be tied closely to Congress' decision with respect to the allocation of allowances.

In January 2008, Duke Energy agreed to participate in The Climate Registry (TCR) as a Founding Reporter. TCR represents a collaboration of 39 U.S. states, seven Canadian provinces and two Mexican states. Participants in the registry agree to report their greenhouse gas emissions using a common platform. A more detailed description can be found by visiting www.theclimateregistry.org.

In 2007, Duke Energy joined the Advisory Committee of the Climate Disclosure Standards Board (CDSB) — an international partnership of seven organizations formed to establish a generally accepted framework for corporate climate change risk-related reporting. The board's long-term goal is to ensure that companies file these reports with regulatory authorities as part of their annual financial reporting. More information is available at www.weforum.org.

Duke Energy has agreed to participate this year in the CDSB's pilot program to "road test" the template, which includes emissions disclosure, physical risks, regulatory risks and risk management strategy. Once the program is up and running in 2009, completed reports will be posted on the Web sites of participating companies.

These are some of the ways Duke Energy is working to keep its stakeholders informed about its strategy for addressing climate change and the associated regulatory risk, now and in the future. For more information on the company's climate disclosure and overall transparency efforts, please also see Duke Energy's 2007|2008 Sustainability Report on the company Web site.

BUILDING BRIDGES TO A LOW-CARBON FUTURE:

Where we are now

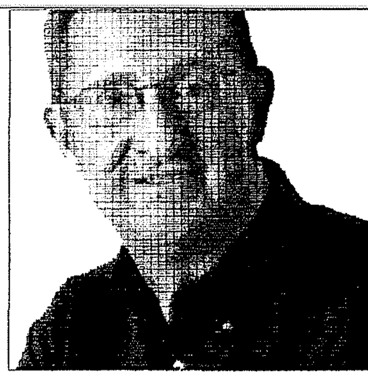
Duke Energy is one of the largest electricity suppliers in North and South America. We serve our retail and wholesale customers reliably and affordably with approximately 40,000 megawatts of electric generating capacity fueled from coal, nuclear, natural gas, hydroelectric and a growing portfolio of renewable energy. In the United States, about 70 percent of the power we generate today comes from coal, which releases carbon dioxide (CO_2) into the atmosphere and is linked to climate change.

CO_2 and most other greenhouse gases (GHG) have always been present, keeping the earth hospitable for life by trapping heat that would otherwise escape into space. We know this as the greenhouse effect. Since the industrial revolution, however, the concentration of GHG in the atmosphere from the burning of fossil fuels and other human activities has increased, trapping more heat and amplifying the natural greenhouse effect.

A majority of the public and policymakers now believe that the earth's climate is changing, caused in part by GHG emitted into the atmosphere from human activity.

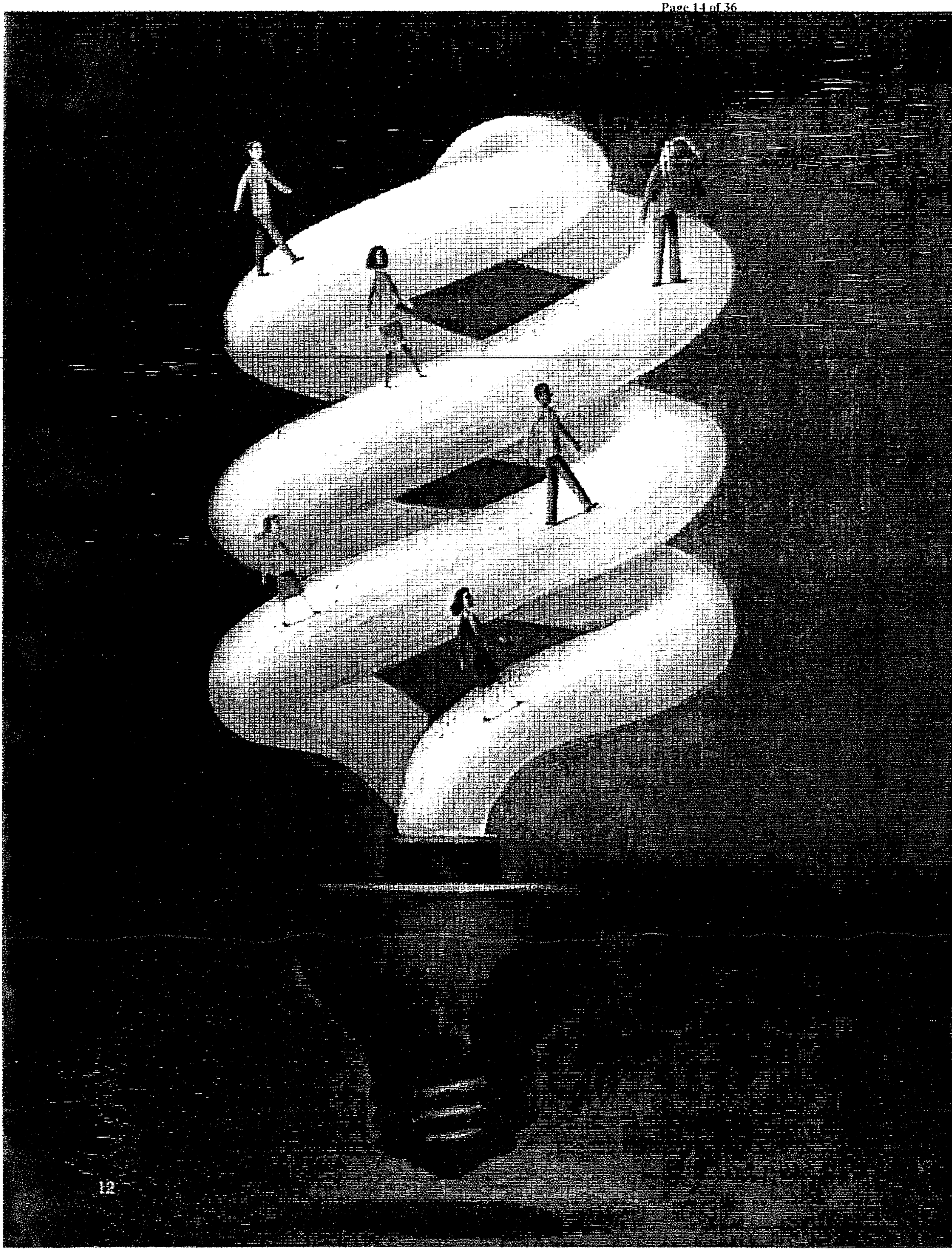
As the third largest emitter of CO_2 in the United States — more than 100 million tons annually, the equivalent of about 10 million cars on the highway — we realize we have a special responsibility to address this issue.

Our focus is on finding practical solutions that will benefit our stakeholders, our nation, our world and future generations.



"I monitor and analyze emerging environmental issues for the company. Over the last few years, the debate over global climate change has intensified. We believe it is no longer a question of if Congress will enact carbon limits, but when — and what will be required. We have to be ready to comply in a way that keeps customer prices competitive."

MIKE STROBEN
Director, Environmental Policy Analysis & Strategy
Duke Energy
Charlotte, N.C



BUILDING BRIDGES TO A LOW-CARBON FUTURE:

Where we are going

We are taking actions today to build a sustainable business that allows our stakeholders and our company to prosper while balancing environmental, social and economic needs.

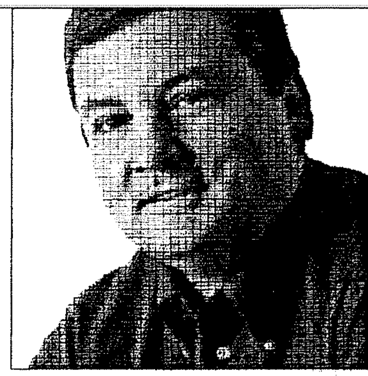
We don't know when federal restrictions on GHG emissions will be enacted, but we must assume they are coming. Some believe it is premature to set specific emission-reduction targets. But without a stake in the ground, we can't expect to make meaningful progress. We believe that preparing for a carbon-constrained world now carries substantially less risk for our customers and our shareholders than if we wait.

To be ready, we are assessing what it would take to cut our CO_2 emissions in half — approximately 50 million tons — by 2030. By then, we will likely have replaced our oldest coal-fired power plants with advanced cleaner-coal and other technologies including nuclear power, natural gas, renewable energy and energy efficiency.

To achieve that reduction and meet our projected electricity demand while keeping our prices competitive, a number of things must happen. These include new technology developments and workable legislative and regulatory solutions.

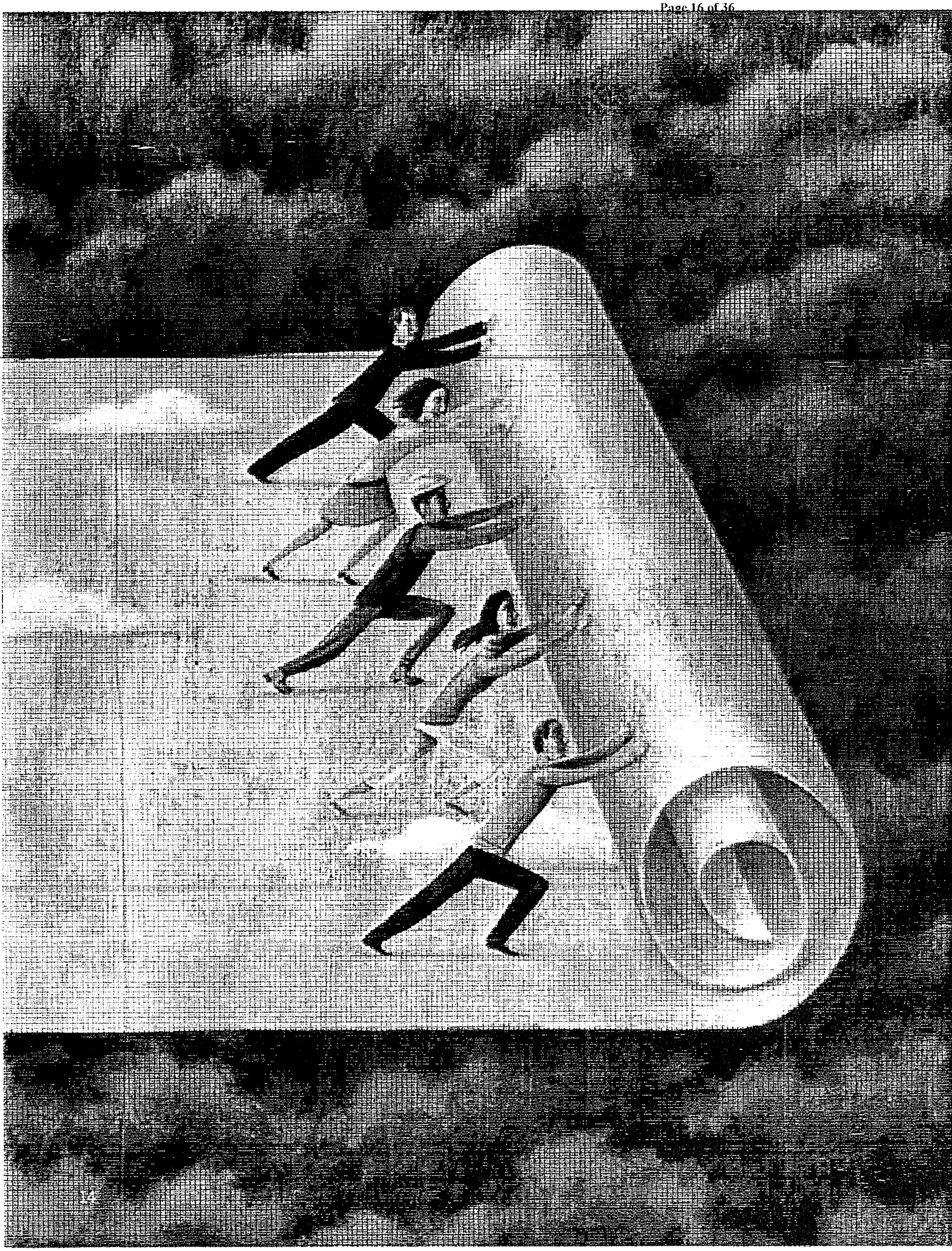
We will need new, lower-emitting coal-based generating technologies so we can continue using coal, our nation's most abundant and economical fuel. We will need advanced zero-emitting nuclear generation. We will need approval of a new business model to significantly expand energy efficiency.

As we realize our vision, we will be ready to adopt new technologies and address unexpected challenges that will surely come along.



"If we are serious about addressing climate change, we have to be serious about nuclear power. Nuclear power plants safely generate more than 70 percent of all carbon-free electricity in the United States. Along with advanced coal, natural gas, renewable energy and energy efficiency, nuclear power must be part of the mix to meet our need for clean, affordable and reliable electricity."

DAVID JONES
Director, Nuclear Policy & Strategy
Duke Energy
Charlotte, N.C.



BUILDING BRIDGES TO A LOW-CARBON FUTURE:

How we will get there

We are taking five steps to build our bridges to a low-carbon future:

First, we are working to shape public policy. We are pursuing passage of federal carbon legislation that will give the electric utility industry the time it needs to make the transition to low-carbon generation, without severe damage to our economy and our customers.

Second, we are pursuing new technology for generation and distribution of electricity and for energy efficiency to reduce our carbon footprint.

Third, we are building new generation plants. We are also developing our talent base so we have the workforce we need to successfully transition to a low-carbon future.

Fourth, we are balancing diverse interests. We are engaging with stakeholders to understand all viewpoints and find the best path to sustainable carbon reduction.

Fifth, we are taking a long view. Halving our CO_2 emissions won't happen overnight. This is a marathon, not a sprint — but the sooner we start, the greater the benefits.

The following pages describe these five steps in greater detail.

"I've been a meter reader and worked in Customer Service, Accounting and Human Resources. In my current role, I bring the customer perspective to lawmakers and their staffs on Capitol Hill. This helps them better understand how we are trying to minimize the impact on our customers as we work to reduce our greenhouse gas emissions."

JOHN HAYSBERT
Manager, Federal Governmental Affairs
Duke Energy
Washington, D.C.

STEP 1

MARITZA BEGAN HER CAREER WITH DUKE ENERGY IN 1999 AS ONE OF THE COMPANY'S FIRST BILINGUAL CUSTOMER SPECIALISTS. SHE LEADS A TEAM RESPONSIBLE FOR FULFILLING CUSTOMER SERVICE REQUESTS, INCLUDING THROUGH THE INTERNET.

HOW WE WILL GET THERE:

Shaping public policy

"Customers are concerned about energy costs. They want to know what they and their families can do to reduce their power bills. In that sense, I think Duke Energy's focus on energy efficiency is coming at the right time."

MARITZA RIVERA
Call Center Team Lead
Duke Energy
Charlotte, N.C.

Congress could pass legislation enacting a greenhouse gas (GHG) cap-and-trade program as early as 2009. As we strive to shape that legislation, we are working to:

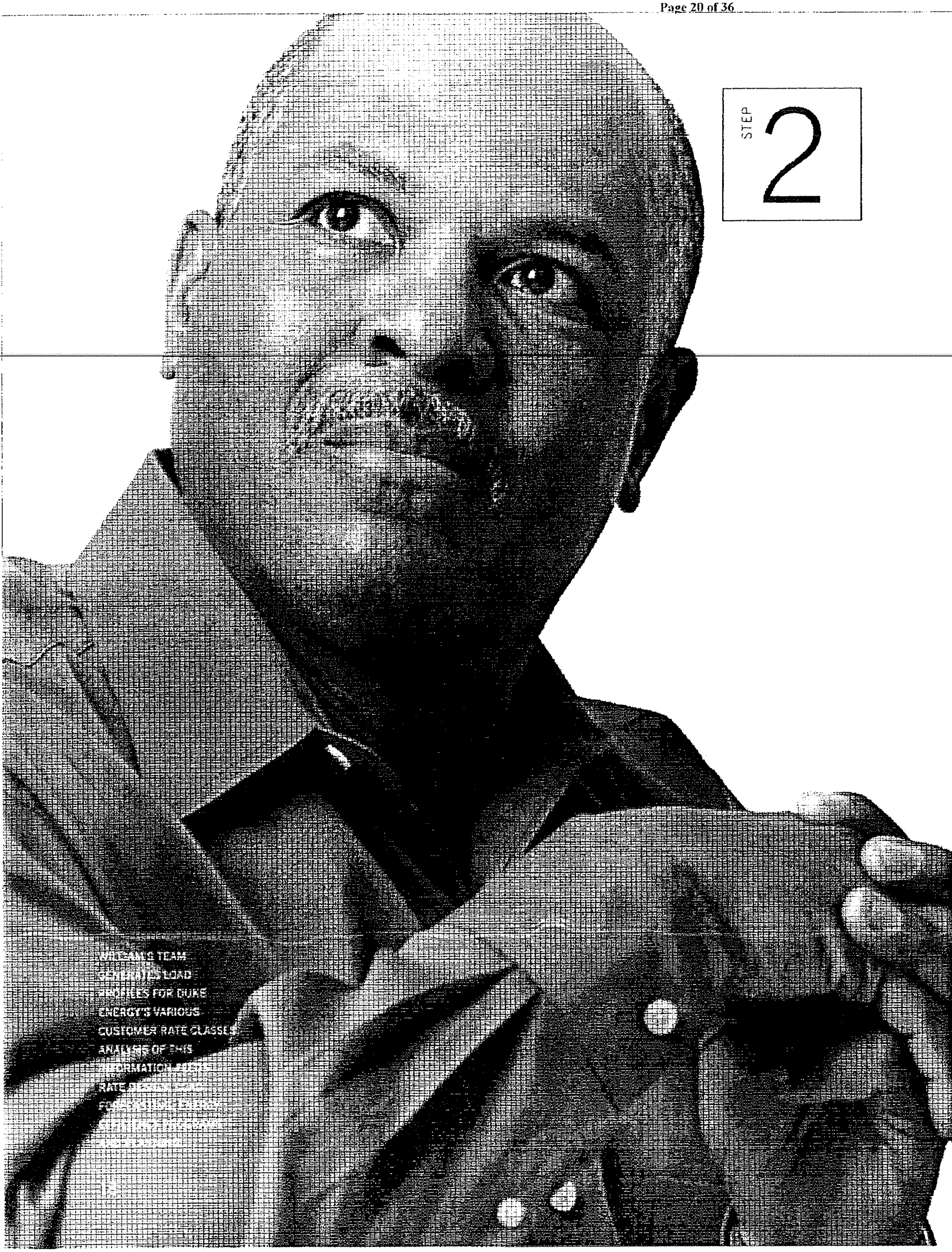
- Better understand the impact alternative policy approaches could have on our industry, our operations and our customers.
- Better understand the technology gap for low- and zero-emitting power generation and promote the funding mechanisms needed to close that gap.
- Communicate with policymakers and other stakeholders, who can help mold and shape federal policy while new technologies develop. This report and our 2007|2008 Sustainability Report are part of that communication process.

Most pending federal legislation calls for reducing our nation's GHG emissions by 60 to 80 percent by 2050. Scientists say the United States and other carbon-intensive nations need to achieve this reduction level by the middle of this century to slow, stop and reverse the effects of climate change. For Duke Energy, we expect that all of our currently operating baseload nuclear and coal-fired generating units will be retired by 2050, with the possible exception of one of our "newest" coal plants in Ohio, which will then be 59 years old.

Given the unknowns — the timing of new low-carbon generation technologies and future carbon dioxide (CO_2) emission constraints — we decided to look instead at what it might take to cut our CO_2 emissions in half — by approximately 50 million tons — by 2030. Due to their relicensing, our three nuclear plants will still be operating, and our planned fourth nuclear plant, Lee Nuclear Station, will have been on line for about 12 years, based on the current schedule. 2030 gives us a more realistic horizon over which to evaluate potential emission-reduction strategies.

With passage of the right cap-and-trade legislation and new technologies, we believe we could successfully reduce our CO_2 emissions like we have our nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions. Through 2010, we will have invested approximately $5 billion to further reduce our SO_2 and NO_x emissions. We project that by 2010, those emissions will be about 70 percent lower than they were in 1997. The SO_2 and NO_x controls we have been installing have the added benefit of capturing a significant amount of mercury.

The point is, we acted proactively before to achieve workable regulations and made the necessary investments in new technology to comply. We can do that again with carbon legislation and forge a solution that protects our customers, our business and our nation's economy.


STEP 2
WILLIAM'S TEAM
GENERATES LOAD
PROFILES FOR DUKE
ENERGY'S VARIOUS
CUSTOMER RATE CLASSES.
ANALYSIS OF THIS

HOW WE WILL GET THERE:

Pursuing new technology

"The Load Research team studies how and when our customers are using energy. This information helps to plan for our customers' future needs and to identify the role that emerging technologies and energy efficiency will play in meeting those needs."

WILLIAM BAKER
Manager, Load Research
Duke Energy
Charlotte, N.C.

We are using new technologies to reduce our GHG emissions on both the supply and demand sides. On the supply side, we're building a cleaner-coal integrated gasification combined cycle (IGCC) plant that will replace a half-century-old coal plant. We're building this 630-megawatt plant in southwestern Indiana, where the geology is conducive to underground capture and permanent storage of CO_2 emissions. As that technology develops, we will evaluate its eventual use at the site.

In the Carolinas, we're building an advanced 800-megawatt coal plant that will eventually replace 1,000 megawatts of old higher-emitting coal units in North Carolina. We're not building an IGCC plant as the geology there is not suitable for CO_2 storage, but this will likely be the last new coal plant we build in North Carolina for at least 20 years. By then, we would expect CO_2 capture technology to advance so it can be used on virtually any coal plant, regardless of the geology. Also in North Carolina we have applied to build more than 1,200 megawatts of natural gas-fired generation capacity to meet increasing demand. This lower-emitting gas generation will also replace older coal units.

We are using our more than three decades of experience in building and operating nuclear plants to plan a new 2,234-megawatt nuclear power plant in South Carolina — a plant that will have zero CO_2 emissions.

We are increasing our use of renewable energy by purchasing renewable capacity to help meet our domestic energy demand with wind, biomass and solar power. Our Commercial Businesses are planning and developing more than 1,000 megawatts of wind power.

On the demand side, we are transforming our passive analog distribution grids into digital information networks to further improve reliability and expand energy efficiency. We are installing "smart" meters, remotely controlled appliance sensors and other energy-saving technologies in customers' homes.

We intend to make energy efficiency part of our standard service offering. This includes providing customers with tools to reduce their energy use without sacrificing comfort, convenience or productivity.

Technology and energy efficiency breakthroughs won't happen without the right regulatory treatment. We seek state regulations that treat energy efficiency as the "fifth fuel" — just like coal, nuclear, natural gas and renewable energy in meeting growing demand. We seek to earn a return on the avoided cost of building new power plants through our energy efficiency gains

NEETA STUDIES AND SELECTS EMERGING TECHNOLOGIES FOR USE AT DUKE ENERGY. SHE ALSO DEVELOPS ADAPTATION STRATEGIES FOR NEW TECHNOLOGIES THAT HAVE THE POTENTIAL TO CONTRIBUTE TO FUTURE EARNINGS.

HOW WE WILL GET THERE:

Building projects and talent

"I seek out and evaluate emerging technologies that can help bring Duke Energy's vision of the future to life. Technology forces us to examine how we do things. In doing so, we discover ways to work more effectively, enhance the customer experience, achieve operational breakthroughs and reduce our environmental impact — all critical to preparing for a low-carbon future."

NEETA PATEL
Director, Technology Development & Application
Duke Energy
Cincinnati, Ohio

Building new baseload power plants requires sophisticated coordination of planning, labor and materials. We have a long tradition of hands-on involvement in large-scale construction projects. In fact, our existing generation fleet was almost entirely engineered and built and is now operated by our own workforce.

Before the merger of Cinergy and Duke Energy in April 2006, both companies were in the process of completing large environmental retrofits — installing scrubbers and SCR (selective catalytic reduction) systems on some of their largest coal-fired units. Experience gained on those projects by our project management teams and through partnerships with design, engineering and construction firms is being transferred to the new power plant projects.

For example, in the Carolinas, project and construction management team leaders from the Marshall Steam Station scrubber project are moving to work on the new Cliffside unit and the scrubber installation on an existing unit of that plant. Project and construction management team leaders working on the scrubber at Belews Creek Steam Station will transition to the new gas-fired units being planned on the sites of the Buck and Dan River steam stations. These project management teams will also work on the new Lee Nuclear Station in South Carolina. In the Midwest, Duke's project management teams completing environmental retrofits at the Gibson and Gallagher coal-fired plants in Indiana are transitioning to the new Edwardsport IGCC plant.

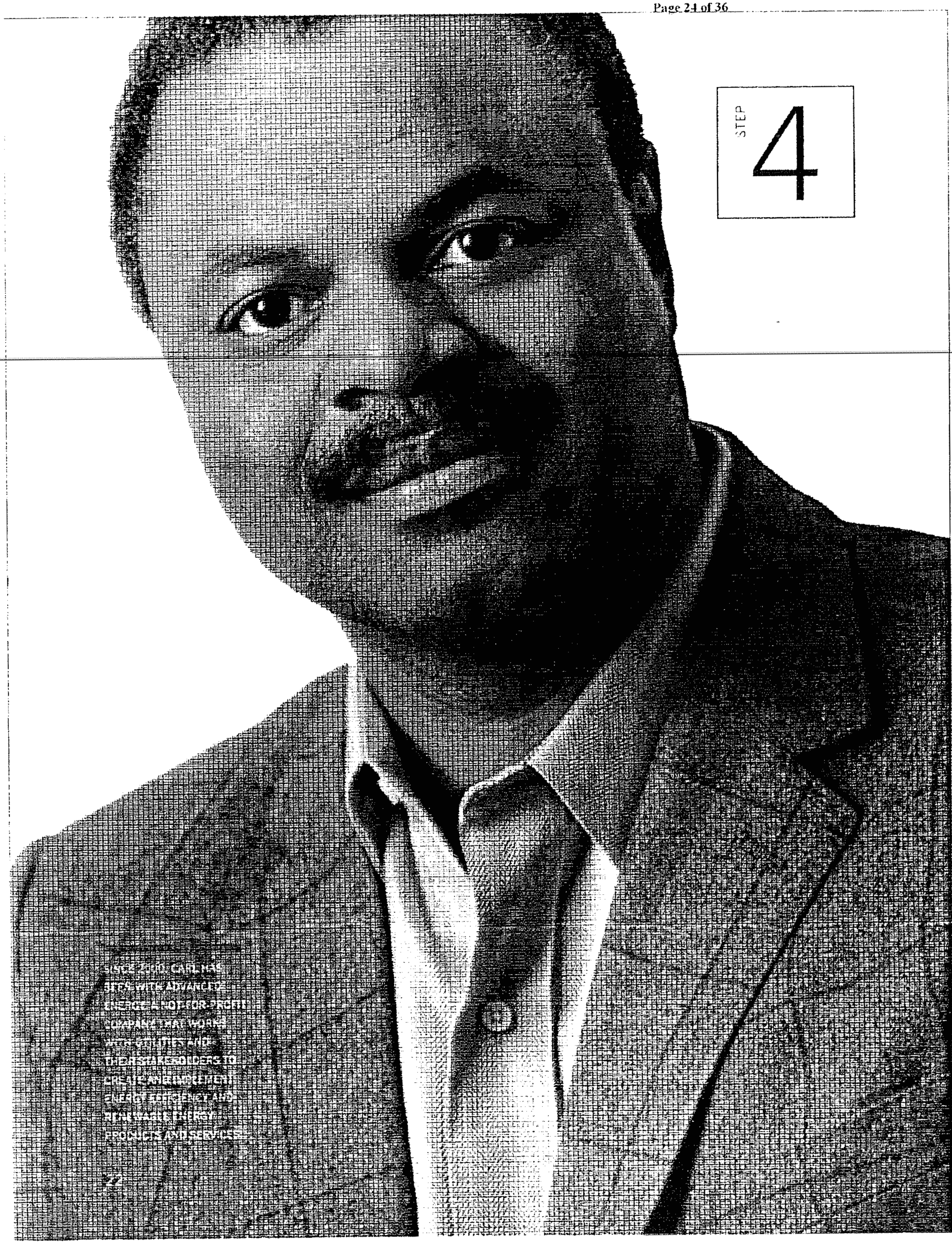
Global demand for engineering, equipment, materials and labor has increased. But with our existing relationships with contractors and suppliers and our use of fixed-price purchase orders, we have already locked in much of the costs for the new coal and gas plants.

We also completed a workforce planning effort to better understand the effects of an aging workforce on our future plans. We found that, due to expected retirements and attrition, we will need to replace almost a third of our workforce over the next five years. Many of our contractors face similar challenges.

Our response strategies include supporting state and local workforce development efforts, providing an employment proposition attractive to a diverse population, broadening existing and initiating new programs to ensure access to top talent, and significantly expanding our employee development, engagement and retention programs.

We have already taken a number of actions, including expanding our staffing functions, ramping up our co-op and summer student hiring programs, developing knowledge transfer strategies, increasing the frequency of internal talent reviews from annually to quarterly, and enhancing our professional development and supervisory/management training programs.

We have also become more active in industry, state and local efforts to develop the workforce of the future. For example, we are supporting K-12 science, technology and math education, and we have partnered with community colleges and technical schools to train technicians to work for us or our contractors. We also advise universities on how to keep curriculum current.



STEP 4

SINCE 2000, CARL HAS BEEN WITH ADVANCED ENERGY, A NOT-FOR-PROFIT COMPANY THAT WORKS WITH UTILITIES AND THEIR STAKEHOLDERS TO CREATE AND IMPLEMENT ENERGY EFFICIENCY AND RENEWABLE ENERGY PRODUCTS AND SERVICES.

HOW WE WILL GET THERE:

Balancing diverse interests

"My job is building relationships. Last year, I coordinated and hosted Duke Energy's 15 'collaboratives' on its proposed energy efficiency plans for North Carolina and South Carolina. These sessions brought together a broad array of stakeholders to find ways to put energy efficiency on a more equal footing with new power plants — a position ultimately endorsed by the North Carolina legislature in a bill passed last summer."

CARL WILKINS
Director, Utility Services
Advanced Energy Corp.
Raleigh, N C

The new rules of engagement in our world, our nation and our industry are conversation and collaboration To effectively address the climate change problem, we are working to engage all of our stakeholders in the debate and in our plans. Climate change doesn't respect borders, so to build support for our strategy we are defining our community broadly.

As a sustainable business, our connections with and among stakeholders are increasingly important to achieving our goals. As we work to build bridges between stakeholder groups, we must also balance their frequently competing needs.

As noted earlier, we will have a greater reliance on energy efficiency to meet our customers' future energy needs. How we develop and implement this new regulatory paradigm will largely be decided by state utility regulators. But the momentum to get the job done is coming from many sectors, including utilities, customer groups and the environmental community.

Last year, we conducted a series of energy efficiency summits in collaboration with a broad range of stakeholders and nationally known energy efficiency experts. These gatherings focused on the benefits an effective energy efficiency program can offer customers and utilities. A dialogue began on the best way to move energy efficiency forward in each state These efforts also provided a framework for building grassroots support for research and development funding for new clean energy technologies, and most importantly, for federal cap-and-trade legislation to reduce GHG emissions.

On the national level, we joined with seven other utilities — representing nearly 20 million customers in 22 states — who committed to a combined investment in energy efficiency of about $1 5 billion annually. When fully implemented in 10 years, this increased level of investment in energy efficiency will reduce CO_2 emissions by about 30 million tons — avoiding the need for 50 500-megawatt peaking power plants.

We also helped form the U S. Climate Action Partnership (USCAP), a group of businesses and leading environmental organizations united in calling on the federal government to move quickly to enact strong national legislation to reduce GHG emissions.

Recognizing that this isn't just a national problem, we're also working very closely with Combat Climate Change (3C), a group of 46 leading companies located around the world. The 3C coalition is committed to finding a common framework for addressing global climate change by 2013.

We believe that engaging diverse stakeholders in our service areas, the nation and around the world will lead to carbon reduction policies that are fair and sustainable for the long term and for all the world's people.

STEP 5

HEIDI IS RESPONSIBLE FOR BUDGETING, FORECASTING AND PROJECT TRACKING FOR DUKE ENERGY'S DEVELOPING WIND ENERGY PORTFOLIO. SHE PREVIOUSLY SERVED AS CONTROLLER FOR THE DIVISION AND BEFORE THAT, SHE WORKED FOR ANOTHER WIND ENERGY COMPANY.

HOW WE WILL GET THERE:

Taking the long view

"I feel that being in wind energy is the best place to be right now. As the technology has advanced and our nation's demand for electricity continues to grow, renewable energy is a growth opportunity for our company and supports our strategy to significantly reduce our carbon emissions."

HEIDI HENTSCHEL
Director, Finance — Wind Energy
Duke Energy Generation Services
Austin, Texas

People today aren't used to looking far into the future or contemplating issues of the scale and complexity of global climate change. We focus on the quick fix. We deal with problems now — then we move on to the next one. Climate change is different. The future can only be changed if we begin today and keep going. Hitting a big target in 2030 or 2050 may be helpful, but to hit longer-term objectives, we need to change the technologies that are vital to a modern society — including those used to generate and distribute electricity.

Today's concentration of CO_2 in the atmosphere is about 380 parts per million (ppm) — only about 100 ppm more than in pre-industrial times. If we continue to use the same technologies, projections of CO_2 concentrations by the end of this century will top 900 ppm. The earth hasn't seen that level of CO_2 for about 35 million years, when things were a lot hotter and wetter than they are today. Scientists say we need to take the first steps to lower our emissions so that future concentrations don't exceed 450 to 550 ppm.

Emissions from less-developed countries will continue to grow as those societies simply improve their lives. This increases the urgency to get to work to develop new non-emitting technologies and lower their cost so they can also be built in the developing world.

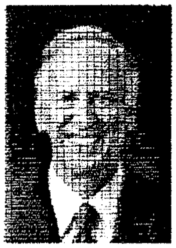
The task for our generation is to get the policy right, get started and stick to it. We need to develop the least costly way to address climate change and do it right. That means policies need to be market based and cover most, if not all, of the economy. The early years of a cap should encourage more energy efficiency and lower-cost actions that can slow, stop and begin to reverse the growth in CO_2 emissions. Policies should encourage the development and commercialization of technologies we will need to make the necessary deep reductions. Policymakers need to avoid the temptation to demand immediate deep emissions cuts, which would result in a greater reliance on natural gas. We must give clean coal technologies the time to develop so that we may deploy them as we retire current technologies.

Future generations will continue this work. The technologies we develop today around CO_2 capture and storage will serve as a bridge for the next generation of technologies. Our grandchildren will need new energy sources, whether advanced solar, space-based solar or even nuclear fusion. We may also find new technologies to remove CO_2 from the atmosphere, perhaps using a combination of biomass and carbon capture and storage. There will be plenty of opportunity for innovation and adaptation to a warmer world.

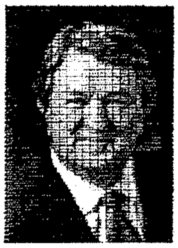
We think of this as "cathedral thinking" — remembering that the architects and builders of the great cathedrals of Europe never saw them completed. Frequently these inspired creations were not finished until the builders' grandchildren were themselves old. Yet that didn't cause them to lose faith, nor did it dull their vision of what might be if they merely began — despite the work, despite the cost and despite the fact they'd never see the end result. Such a commitment is needed for achieving a low-carbon future.

Board of Directors

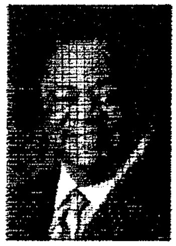
WILLIAM
BARNET III



G. ALEX
BERNHARDT SR.



MICHAEL G.
BROWNING



PHILLIP R. COX

DANIEL R. DIMICCO

ANN MAYNARD
GRAY

WILLIAM BARNET III
Chairman, President and CEO,
The Barnet Co. Inc. and
Barnet Development Corp.;
Chair, Finance and Risk Management Committee; Member, Nuclear Oversight Committee

Director of Duke Energy and its predecessor companies since 2005. Barnet is the mayor of Spartanburg, S.C. He serves on the board of Bank of America and is a trustee of the Duke Endowment.

G. ALEX BERNHARDT SR.
Chairman and CEO,
Bernhardt Furniture Co.;
Member, Audit and Nuclear Oversight Committees

Director of Duke Energy and its predecessor companies since 1991. Besides leading the family business in Lenoir, N.C., Bernhardt serves on the board of Communities In Schools. He is past president of the American Furniture Manufacturers Association and of the International Home Furnishings Marketing Association.

MICHAEL G. BROWNING
President and Chairman of the Board,
Browning Investments Inc.;
Member, Compensation, Corporate Governance, and Finance and Risk Management Committees

Director of Duke Energy and its predecessor companies since 1990. Browning serves on the boards of the Indianapolis Convention & Visitors Association and the Indianapolis Museum of Art. He is a member of the Indiana Public Officer Compensation Committee.

PHILLIP R. COX
President and CEO,
Cox Financial Corp.;
Chair, Audit Committee

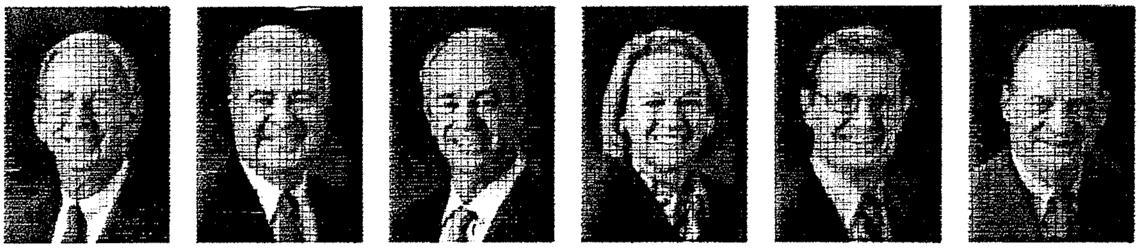
Director of Duke Energy and its predecessor companies since 1994. Cox is chairman of the board of Cincinnati Bell and serves on the boards of The Timken Company, Diebold Inc., the Cincinnati Business Committee, Touchstone Mutual Funds and the University of Cincinnati.

DANIEL R. DIMICCO
Chairman, President and Chief Executive Officer,
Nucor Corporation;
Member, Compensation and Corporate Governance Committees

Director of Duke Energy since 2007. DiMicco began his career with Nucor Corporation in 1982 and held a number of senior positions before being named chairman in 2006. He is a former chair of the American Iron and Steel Institute.

ANN MAYNARD GRAY
Former President,
Diversified Publishing Group of ABC Inc.;
Lead Director; Chair, Corporate Governance Committee; Member, Compensation and Finance and Risk Management Committees

Director of Duke Energy and its predecessor companies since 1994. Gray has held a number of senior positions with American Broadcasting Companies and serves on the boards of the Phoenix Companies and Elan Corp. plc



JAMES H. HANCE JR. JAMES T. RHODES JAMES E. ROGERS MARY L. SCHAPIRO PHILIP R. SHARP DUDLEY S. TAFT

JAMES H HANCE JR.
Retired Vice Chairman, Chief Financial Officer and Board Member, Bank of America Corp.; Chair, Compensation Committee; Member, Finance and Risk Management Committee

Director of Duke Energy and its predecessor companies since 2005. A certified public accountant, Hance spent 17 years with Price Waterhouse. He serves on the boards of Sprint Nextel Corp., Cousins Properties Inc. and Rayonier Corp.

JAMES T RHODES
Retired Chairman, President and CEO, Institute of Nuclear Power Operations (INPO); Chair, Nuclear Oversight Committee; Member, Audit Committee

Director of Duke Energy and its predecessor companies since 2001. Rhodes is a member of the Electric Power Research Institute's advisory council and a former board member of INPO, the Nuclear Energy Institute, Edison Electric Institute and the Southeastern Electric Exchange

JAMES E. ROGERS
Chairman, President and CEO, Duke Energy

Rogers became president and CEO of Duke Energy in 2006, having served as chairman and CEO of Cinergy Corp. since 1994 and PSI Energy since 1988 He is chairman of the Institute for Electric Efficiency and the Edison Foundation, and serves as co-chair of the National Action Plan for Energy Efficiency and the Alliance to Save Energy. He is a director of Fifth Third Bancorp and Cigna Corp. and serves on the boards and Executive Committees of the World Business Council for Sustainable Development and the Edison Electric Institute. He is also a board member of the Nuclear Energy Institute, the Institute of Nuclear Power Operations and the Nicholas Institute for Environmental Policy Solutions.

MARY L SCHAPIRO
Chief Executive Officer, Financial Industry Regulatory Authority; Member, Audit and Corporate Governance Committees

Director of Duke Energy and its predecessor companies since 1999. Schapiro previously served as chairman and CEO of the National Association of Securities Dealers, as chairman of the Commodity Futures Trading Commission and on the Securities and Exchange Commission. She currently serves on the board of Kraft Foods Inc

PHILIP R SHARP
President, Resources for the Future; Member, Audit and Nuclear Oversight Committees

Director of Duke Energy since 2007, having served on one of its predecessor companies from 1995 to 2006. A former member of the Indiana delegation to the U.S. House of Representatives, Sharp served as Congressional chair of the National Commission on Energy Policy and was a member of the House Energy and Commerce Committee.

DUDLEY S TAFT
President and CEO, Taft Broadcasting Co.; Member, Compensation and Finance and Risk Management Committees

Director of Duke Energy and its predecessor companies since 1985. Taft serves on the boards of the Unifi Mutual Holding Co. and Fifth Third Bancorp. He is chairman of the Cincinnati Association for the Arts and a trustee of the Cincinnati Convention & Visitors Bureau

Executive Management

HENRY B. BARRON JR.

STEPHEN G. DE MAY

LYNN J. GOOD

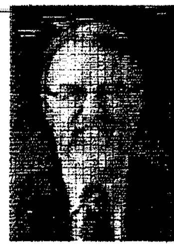
DAVID L. HAUSER

JULIA S. JANSON

MARC E. MANLY

BEVERLY K. MARSHALL

SANDRA P. MEYER



DAVID W. MOHLER

HENRY B. BARRON JR.
Group Executive and Chief Nuclear Officer

Barron became Duke Energy's chief nuclear officer in 2004. He has been responsible for the safe operation of the company's nuclear generating stations. He joined the company in 1972 as a nuclear power plant engineer. Barron plans to retire March 31, 2008.

STEPHEN G. DE MAY
Vice President and Treasurer

De May leads the treasury function for Duke Energy, as well as risk management, insurance, and administration of pension and retirement plan assets. He previously served as general manager, corporate finance and assistant treasurer.

LYNN J. GOOD
Group Executive and President, Commercial Businesses

Good is responsible for Duke Energy's Midwest nonregulated generation, Duke Energy International, Duke Energy Generation Services, the telecommunications businesses, and all corporate development and merger and acquisition activities. She previously served as senior vice president and treasurer.

DAVID L. HAUSER
Group Executive and Chief Financial Officer

Hauser became Duke Energy's chief financial officer in 2004. He leads the financial function, which includes the controller's office, treasury, tax, risk management and insurance. Hauser joined the company in 1973.

JULIA S. JANSON
Senior Vice President, Ethics and Compliance and Corporate Secretary

Janson directs Duke Energy's ethics and compliance program and serves as corporate secretary. She served as Cinergy's chief compliance officer since 2004 and corporate secretary since 2000.

MARC E. MANLY
Group Executive and Chief Legal Officer

Manly leads Duke Energy's office of general counsel, which includes legal, internal audit, ethics and compliance, human resources and the corporate secretary. He served as Cinergy's executive vice president and chief legal officer since 2002.

BEVERLY K. MARSHALL
Vice President, Federal Policy and Government Affairs

Marshall manages Duke Energy's Washington, D.C., office and serves as the company's primary liaison with the U.S. Congress. She joined the company in 1999 and has 20 years of experience in government affairs.

SANDRA P. MEYER
President, Duke Energy Ohio and Duke Energy Kentucky

Meyer leads Duke Energy's Ohio and Kentucky operations, which serve more than 820,000 customers. She previously served as group vice president of customer service, sales and marketing for Duke Power.

DAVID W. MOHLER
Vice President and Chief Technology Officer

Mohler is responsible for the development and application of technologies in support of Duke Energy's strategic objectives. He previously served as vice president of strategic planning.


CATHY S. ROCHE


CHRISTOPHER C. ROLFE


ELLEN T. RUFF


JIM L. STANLEY


R. SEAN TRAUSCHKE


B. KEITH TRENT


JAMES L. TURNER


STEVEN K. YOUNG

CATHY S. ROCHE
Senior Vice President and
Chief Communications Officer

Roche is responsible for directing and managing Duke Energy's communications with internal and external audiences, as well as executive communications, corporate publications, advertising, and brand management and strategy.

CHRISTOPHER C. ROLFE
Group Executive and
Chief Administrative Officer

Rolfe leads several of Duke Energy's corporate functions, including supply chain, information technology, operations services and other administrative activities. He previously served as group executive and chief human resources officer.

ELLEN T. RUFF
President,
Duke Energy Carolinas

Ruff leads Duke Energy's utility business in North Carolina and South Carolina, which serves more than 2.3 million customers. She was formerly group vice president of planning and external relations for Duke Power.

JIM L. STANLEY
President,
Duke Energy Indiana

Stanley leads Duke Energy's Indiana utility business, which serves more than 770,000 customers. He previously served as vice president of field operations for Duke Energy's Midwest service area.

R. SEAN TRAUSCHKE
Senior Vice President,
Investor Relations and Financial Planning

Trauschke is responsible for monitoring trends in investment markets and for maintaining key relationships with investors, financial analysts and financial institutions. He also has oversight of corporate financial planning and analysis.

B. KEITH TRENT
Group Executive and Chief Strategy,
Policy and Regulatory Officer

Trent is responsible for strategy, federal policy and government affairs, energy efficiency and technology initiatives, environmental health and safety policy, corporate communications, and sustainability and community affairs. He also has oversight of the regulated utility companies in five states.

JAMES L. TURNER
Group Executive; President and
Chief Operating Officer,
U.S. Franchised Electric and Gas

Turner has overall profit and loss responsibility for Duke Energy's U.S. Franchised Electric and Gas business, which serves approximately 3.9 million customers in five states. He leads the company's fossil/hydro generation, power delivery, gas distribution, customer service, wholesale business and new generation projects organizations.

STEVEN K. YOUNG
Senior Vice President and Controller

Young is responsible for planning and directing the accounting affairs of Duke Energy, including preparation of financial statements and accounting and regulatory reports. He joined the company in 1980 as a financial assistant.

Duke Energy at a Glance

U.S. Franchised Electric and Gas

EXPECTED 2008 ONGOING EARNINGS BEFORE INTEREST AND TAXES (EBIT) CONTRIBUTION

74%*

BUSINESS DESCRIPTION

U.S. Franchised Electric and Gas (USFE&G) consists of Duke Energy's regulated generation, electric and gas transmission and distribution systems. Its generation portfolio is a mix of fuel sources — coal, oil/natural gas, nuclear and hydro-electric. USFE&G is Duke Energy's largest business segment and primary source of earnings growth.

NOTABLE STATISTICS

Electric Operations

- Owns approximately 28,000 megawatts of generating capacity
- Supplies electric service to approximately 3.9 million customers
- Serves territories in five states — North Carolina, South Carolina, Ohio, Indiana and Kentucky — that total about 47,000 square miles
- Operates 148,700 miles of distribution lines and a 20,900-mile transmission system

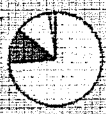
Gas Operations

- Provides regulated transmission and distribution service to approximately 500,000 customers over a 3,000-square-mile service territory in Ohio and Kentucky

Commercial Power

EXPECTED 2008 ONGOING EBIT CONTRIBUTION

12%*



BUSINESS DESCRIPTION

Commercial Power owns, operates and manages nonregulated power plants, primarily in the Midwest. Commercial Power also includes Duke Energy Generation Services (DEGS), which develops, owns and operates generation sources (including wind assets) that serve large energy consumers, municipalities, utilities and industrial facilities.

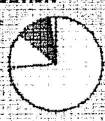
NOTABLE STATISTICS

- Owns and operates a balanced generation portfolio of approximately 8,000 megawatts
- Most of the generation output in Ohio, over 21 million megawatt-hours annually, is supplied to regulated customers
- DEGS has contracted to purchase wind turbines that are capable of generating approximately 240 megawatts when placed in commercial operation beginning in 2008 and 2009

Duke Energy International

EXPECTED 2008 ONGOING EBIT CONTRIBUTION

12%*



BUSINESS DESCRIPTION

Duke Energy International (DEI) operates and manages power generation facilities located in the Central and South American countries of Argentina, Brazil, Ecuador, El Salvador, Guatemala and Peru. DEI also owns equity investments in Saudi Arabia and Greece.

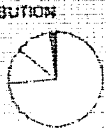
NOTABLE STATISTICS

- Owns, operates or has substantial interests in approximately 4,000 net megawatts of generation facilities
- About 75 percent of DEI's generating capacity is hydroelectric, and approximately 90 percent is either currently contracted or receives a system capacity payment

Crescent Resources

EXPECTED 2008 ONGOING EBIT CONTRIBUTION

2%*



BUSINESS DESCRIPTION

Crescent Resources is effectively a 50-50 joint venture with Morgan Stanley Real Estate Fund. Crescent manages land holdings and develops high-quality commercial, residential and multi-family real estate projects.

NOTABLE STATISTICS

- Located in 10 states, primarily in the southeastern and southwestern United States
- Owns 900,000 square feet of commercial, industrial and retail space, with an additional 500,000 square feet under construction
- Manages approximately 122,608 acres of land

*Percent of 2008 forecasted ongoing total segment EBIT does not include results for the operations labeled as Other.

Non-GAAP Financial Measures

2007 AND 2006 ONGOING DILUTED EARNINGS PER SHARE ("EPS")

Duke Energy's 2007 Summary Annual Report references 2007 and 2006 ongoing diluted EPS of $1.24 and $0.99, respectively. Ongoing diluted EPS is a non-GAAP (generally accepted accounting principles) financial measure, as it represents diluted EPS from continuing operations, adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The following is a reconciliation of reported diluted EPS from continuing operations to ongoing diluted EPS for 2007 and 2006:

	2007	2006
Diluted EPS from continuing operations, as reported	**$ 1.20**	$ 0.91
Diluted EPS from discontinued operations, as reported	**(0.02)**	0.66
Diluted EPS, as reported	**1.18**	$ 1.57
Adjustments to reported EPS:		
Diluted EPS from discontinued operations	**0.02**	(0.66)
Diluted EPS impact of special items (see detail below)	**0.04**	0.08
Diluted EPS, ongoing	**$ 1.24**	**$ 0.99**

The following is the detail of the $(0.04) in special items impacting diluted EPS for 2007:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2007 Diluted EPS Impact
Convertible debt costs associated with the spinoff of Spectra Energy	$(21)	—	$(0.02)
Costs to achieve the Cinergy merger	(54)	19	(0.03)
IT severance costs	(12)	4	—
Settlement reserves and adjustments	24	(9)	0.01
Total Diluted EPS impact			**$(0.04)**

The following is the detail of the $(0.08) in special items impacting diluted EPS for 2006:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2006 Diluted EPS Impact
Settlement reserves	$(165)	58	$(0.09)
Gain on sale of interest in Crescent	246	(124)	0.10
Impairment of Campeche investment	(50)	—	(0.04)
Costs to achieve the Cinergy merger	(128)	45	(0.07)
Tax adjustments		27	0.02
Total Diluted EPS impact			**$(0.08)**

2008 EMPLOYEE INCENTIVE TARGET MEASURE

Duke Energy's 2007 Summary Annual Report references the company's 2008 employee incentive target. The EPS measure used for employee incentive bonuses is based on ongoing diluted EPS. Ongoing diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for ongoing diluted EPS is reported diluted EPS from continuing operations, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast special items for future periods.

ANTICIPATED ONGOING DILUTED EPS GROWTH RATES THROUGH 2012

Duke Energy's 2007 Summary Annual Report references the expected range of growth of 5 to 7 percent in ongoing diluted EPS through 2012 on a compound annual growth rate ("CAGR") basis. These growth percentages are based on anticipated ongoing diluted EPS amounts for future periods. Ongoing diluted EPS is a non-GAAP financial measure as it represents anticipated diluted EPS from continuing operations, adjusted for the impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for ongoing diluted EPS is reported diluted EPS from continuing operations which includes the impact of special items. Due to the forward-looking nature of ongoing diluted EPS and related growth rates for future periods, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast special items for future periods.

FORECASTED 2008 ONGOING SEGMENT AND ONGOING TOTAL SEGMENT EBIT

Duke Energy's 2007 Summary Annual Report includes a discussion of forecasted 2008 ongoing EBIT for each of Duke Energy's reportable segments as a percentage of forecasted 2008 ongoing total segment EBIT. Forecasted 2008 ongoing segment and total segment EBIT amounts are non-GAAP financial measures, as they reflect segment and total segment EBIT, adjusted for the impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for forecasted ongoing segment EBIT is reported segment EBIT from continuing operations, which includes the impact of special items. The most directly comparable GAAP measure for ongoing total segment EBIT is reported total segment EBIT, which includes the impact of special items. Due to the forward-looking nature of these non-GAAP financial measures for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures is not available at this time, as management is unable to forecast special items for future periods.

Investor Information

Annual Meeting
The 2008 Annual Meeting of Duke Energy Shareholders will be:
Date: Thursday, May 8, 2008
Time: *10 a.m.*
Place: O.J. Miller Auditorium,
Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services
Shareholders may call 800-488-3853 or 704-382-3853 with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Additionally, registered users of DUK-Online, our online account management service, may access their accounts through the Internet.

Send written requests to:
Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005

For electronic correspondence, visit www.duke-energy.com/contactIR.

Stock Exchange Listing
Duke Energy's common stock is listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Addresses
Corporate home page:
www.duke-energy.com
Investor Relations:
www.duke-energy.com/investors

InvestorDirect Choice Plan
The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available.

The plan also provides for full reinvestment, direct deposit or cash payment of dividends. Additionally, participants may register for DUK-Online, our online account management tool.

Financial Publications
Duke Energy's summary annual report, SEC Form 10-K and related financial publications can be found on our Web site at www.duke-energy.com/investors. Printed copies are also available free of charge upon request.

Duplicate Mailings
If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar
Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common stock issues.

Dividend Payment
Duke Energy has paid quarterly cash dividends on its common stock for 81 consecutive years. For the rest of 2008, dividends on common stock are expected to be paid, subject to declaration by the Board of Directors, on June 16, Sept. 16 and Dec. 16, 2008.

Bond Trustee
If you have questions regarding your bond account, call 800-275-2048, or write to:
The Bank of New York
Global Trust Services
101 Barclay Street
New York, NY 10286

Send Us Feedback
We welcome your opinion on this summary annual report. Please visit www.duke-energy.com/investors, where you can view and provide feedback on both the print and online versions of this report. Or contact Investor Relations directly.

Duke Energy is an equal opportunity employer. This report is published solely to inform shareholders and is not to be considered an offer, or the solicitation of an offer, to buy or sell securities.

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Forward-Looking Statement

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to: state, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements; state, federal and foreign legislation and regulatory initiatives that affect cost and investment recovery, or have an impact on rate structures; costs and effects of legal and administrative proceedings, settlements, investigations and claims; industrial, commercial and residential growth in Duke Energy Corporation's (Duke Energy) service territories; additional competition in electric markets and continued industry consolidation; political and regulatory uncertainty in other countries in which Duke Energy conducts business; the influence of weather and other natural phenomena on Duke Energy operations, including the economic, operational and other effects of hurricanes, droughts, ice storms and tornadoes; the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates; unscheduled generation outages, unusual maintenance or repairs and electric transmission system constraints; the performance of electric generation and of projects undertaken by Duke Energy's nonregulated businesses; the results of financing efforts, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions; declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans; the level of creditworthiness of counterparties to Duke Energy's transactions; employee workforce factors, including the potential inability to attract and retain key personnel; growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power and other projects; the effect of accounting pronouncements issued periodically by accounting standard-setting bodies; and the ability to successfully complete merger, acquisition or divestiture plans.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Duke Energy®

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OUR DIRECTION IN 2008 AND BEYOND

We must pursue a balanced approach to meeting future energy needs.

- In pursuing new supply options, we consider whether they are available, affordable, reliable and clean.
- By carefully balancing these criteria, we can make the best decisions for our customers and our company.
- Our options include energy efficiency, coal gasification, advanced pulverized coal, nuclear, natural gas-fired generation and renewable energy.

We must balance the reality of a carbon-constrained future with our customers' energy demands.

- Environmental legislation will significantly affect Duke Energy. We aim for fairness for our customers and shareholders.
- In our regulated and commercial businesses, we will pursue low-carbon solutions — like clean coal and natural gas — and no-carbon solutions — like nuclear and renewable energy. We will also pursue innovative energy efficiency and Utility of the Future (advanced power grid) initiatives.
- We will push for the development of new technologies to reduce carbon emissions. Until those technologies are available, we will meet demand with current options.

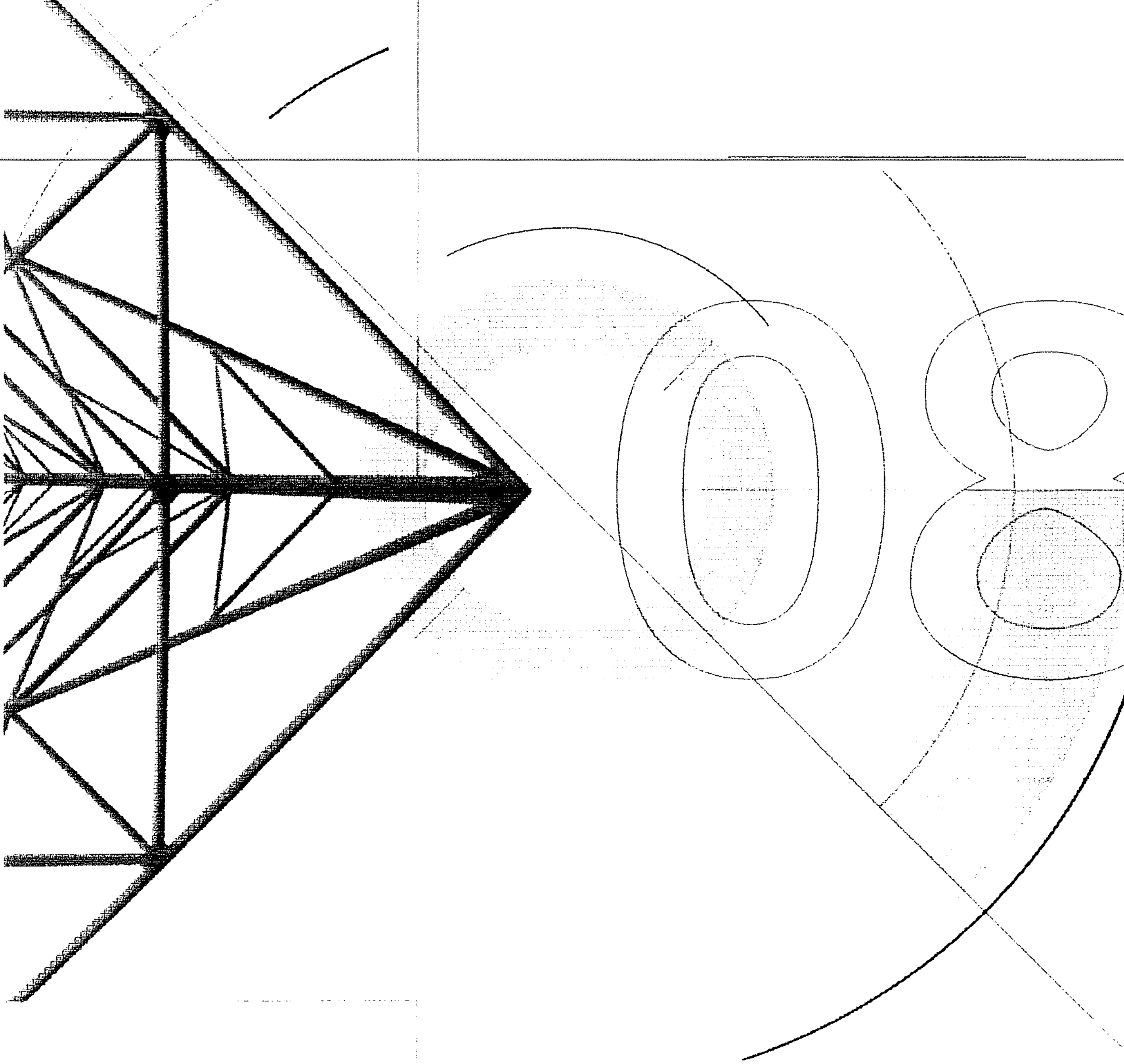
We must find the path to success during this era of rising costs.

- We expect to see increased costs from modernizing our grid and developing new generation. We will effectively manage the costs of these and other capital projects.
- By running our business well and providing excellent customer service, we can minimize price impacts to our customers and maintain the financial health of the company.

We must deliver on our commitments.

- We will steadily grow earnings — making our company attractive to investors — and achieve our employee incentive target of $1.27 of ongoing diluted earnings per share.
- We will continue to balance our regulated and commercial investments based on the business environment.
- We will strive to be simply the best.

Redefining
Our Boundaries

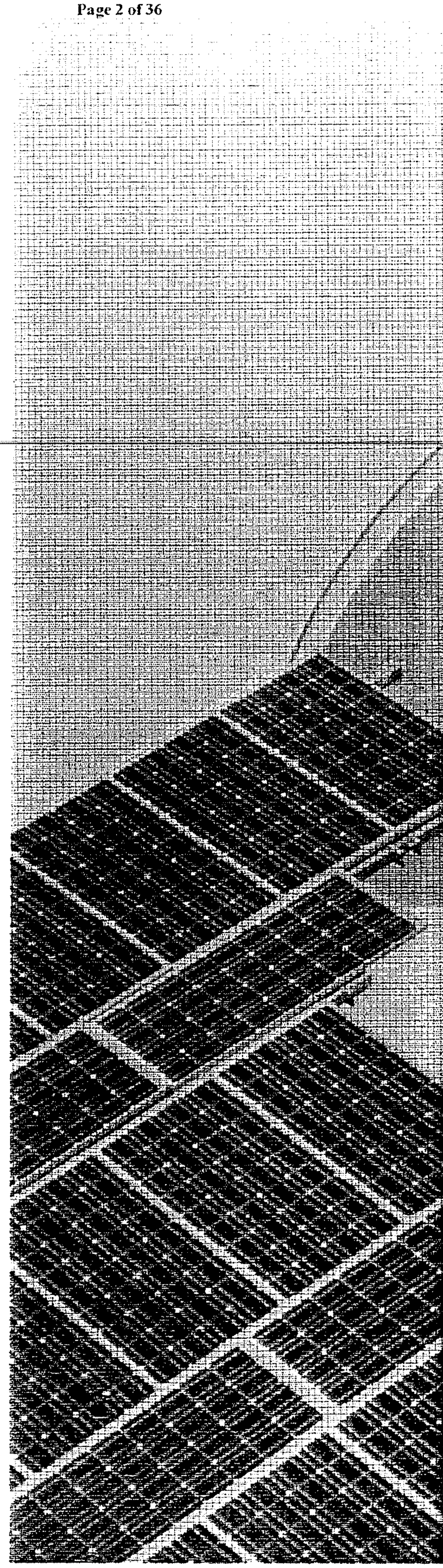


2008 Summary Annual Report

Duke Energy

Profile

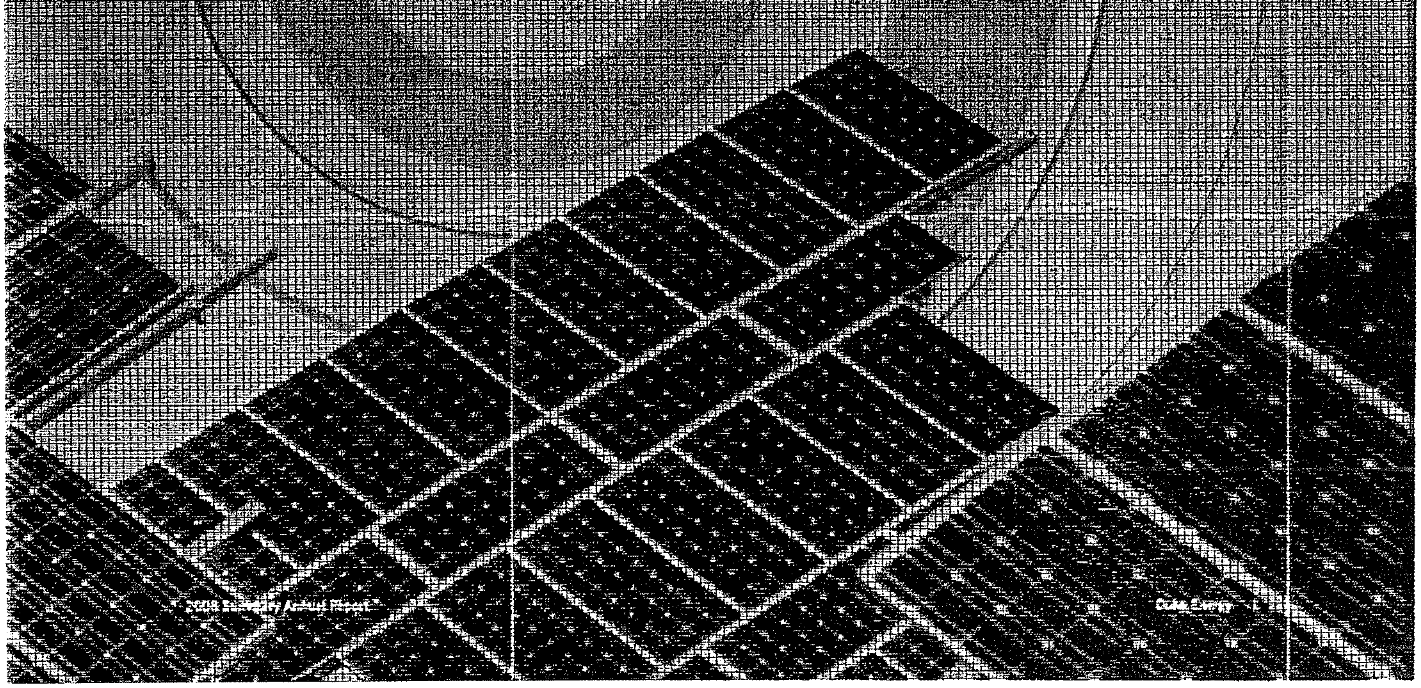
Duke Energy is the third largest electric power holding company in the United States, based on kilowatt-hour sales. Our regulated utility operations serve approximately 4 million customers located in five states in the Southeast and Midwest, representing a population of approximately 11 million people. Our commercial power and international business segments own and operate diverse power generation assets in North America and Latin America, including a growing portfolio of renewable energy assets in the United States.



Contents

Redefining our boundaries

We are redefining our boundaries to help accelerate our nation's transition to a low-carbon future. To achieve our mission of delivering affordable, reliable and increasingly clean energy, we are investing in renewables, new cleaner-coal technology, new nuclear capacity and a more efficient and responsive smart grid. We are promoting new regulatory frameworks to advance energy efficiency and advocating responsible climate change legislation. These initiatives put us in a unique position to grow our business, even during uncertain times.



Financial Highlights[a]

(In millions, except per-share amounts)	2008	2007	2006	2005	2004
Statement of Operations					
Total operating revenues	**$13,207**	$12,720	$10,607	$ 6,906	$ 6,357
Total operating expenses	**10,765**	10,222	9,210	5,586	5,074
Gains on sales of investments in commercial and multi-family real estate	**—**	—	201	191	192
Gains (losses) on sales of other assets and other, net	**69**	(5)	223	(55)	(435)
Operating income	**2,511**	2,493	1,821	1,456	1,040
Total other income and expenses	**121**	428	354	217	130
Interest expense	**741**	685	632	381	425
Minority interest (benefit) expense	**(4)**	2	13	24	(15)
Income from continuing operations before income taxes	**1,895**	2,234	1,530	1,268	810
Income tax expense from continuing operations	**616**	712	450	375	192
Income from continuing operations	**1,279**	1,522	1,080	893	618
Income (loss) from discontinued operations, net of tax	**16**	(22)	783	935	872
Income before cumulative effect of change in accounting principle and extraordinary items	**1,295**	1,500	1,863	1,828	1,490
Cumulative effect of change in accounting principle, net of tax and minority interest	**—**	—	—	(4)	—
Extraordinary items, net of tax	**67**	—	—	—	—
Net income	**1,362**	1,500	1,863	1,824	1,490
Dividends and premiums on redemption of preferred and preference stock	**—**	—	—	12	9
Earnings available for common stockholders	**$ 1,362**	$ 1,500	$ 1,863	$ 1,812	$ 1,481
Ratio of Earnings to Fixed Charges	**3.4**	3.7	2.6	2.4	1.6
Common Stock Data					
Shares of common stock outstanding[b]					
Year-end	**1,272**	1,262	1,257	928	957
Weighted average — basic	**1,265**	1,260	1,170	934	931
Weighted average — diluted	**1,268**	1,266	1,188	970	966
Earnings per share (from continuing operations)					
Basic	**$ 1.01**	$ 1.21	$ 0.92	$ 0.94	$ 0.65
Diluted	**1.01**	1.20	0.91	0.92	0.64
Earnings (loss) per share (from discontinued operations)					
Basic	**$ 0.02**	$ (0.02)	$ 0.67	$ 1.00	$ 0.94
Diluted	**0.01**	(0.02)	0.66	0.96	0.90
Earnings per share (before cumulative effect of change in accounting principle and extraordinary items)					
Basic	**$ 1.03**	$ 1.19	$ 1.59	$ 1.94	$ 1.59
Diluted	**1.02**	1.18	1.57	1.89	1.54
Earnings per share (from extraordinary items)					
Basic	**$ 0.05**	$ —	$ —	$ —	$ —
Diluted	**0.05**	—	—	—	—
Earnings per share					
Basic	**$ 1.08**	$ 1.19	$ 1.59	$ 1.94	$ 1.59
Diluted	**1.07**	1.18	1.57	1.88	1.54
Dividends per share[c]	**0.90**	0.86	1.26	1.17	1.10
Balance Sheet					
Total assets	**$53,077**	$49,686	$68,700	$54,723	$55,770
Long-term debt including capital leases, less current maturities	**$13,250**	$ 9,498	$18,118	$14,547	$16,932

a Significant transactions reflected in the results above include: 2007 spin-off of the natural gas businesses (see Note 1 to the Consolidated Financial Statements in Duke Energy's 2008 Form 10-K, "Summary of Significant Accounting Policies"), 2006 merger with Cinergy (see Note 3 to the Consolidated Financial Statements in Duke Energy's 2008 Form 10-K, "Acquisitions and Dispositions of Businesses and Sales of Other Assets"), 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 3 to the Consolidated Financial Statements in Duke Energy's 2008 Form 10-K, "Acquisitions and Dispositions of Businesses and Sales of Other Assets"), 2005 DENA disposition, 2005 deconsolidation of DCP Midstream effective July 1, 2005, 2005 DCP Midstream sale of TEPPCO and 2004 sale of the former DENA Southeast plants.

b 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy (see Note 3 to the Consolidated Financial Statements in Duke Energy's 2008 Form 10-K, "Acquisitions and Dispositions of Businesses and Sales of Other Assets").

c 2007 decrease due to the spin-off of the natural gas businesses to shareholders on January 2, 2007, as dividends subsequent to the spin-off were set to approximate the combined dividends of Duke Energy and Spectra Energy such that the sum of the dividends of the two stand-alone companies approximated the former total dividend of Duke Energy prior to the spin-off.

See Notes to Consolidated Financial Statements in Duke Energy's 2008 Form 10-K.

Chairman's Letter to Stakeholders

Dear fellow investors, customers, employees and all who have an interest in our success — our partners, suppliers, policymakers, regulators and communities:

Last year, I wrote about how we are building an environmentally advanced generation and distribution system as a bridge to a low-carbon future. But that was before the credit crisis of 2008. Has the current economic crisis impacted our plans? Absolutely. We have delayed some capital spending and are reducing our operating costs every way we can.

But even in this economic crisis, we must continue to execute the long-term plans we have described in past annual reports. We will continue to act decisively to transition Duke Energy's business model from one reflecting 20th century needs to a new model based on 21st century realities.

REDEFINING OUR BOUNDARIES

These new realities include the need for increased energy efficiency, cleaner coal technologies, distributed generation, new nuclear energy and renewables, including wind, solar and biomass. In 2008, I challenged our employees to work together to develop these initiatives by redefining our boundaries.

We made progress. We learned that some boundaries are imagined and some are real. The imagined ones usually show up in conversations ending with: "Well, we've always done it that way." The real boundaries challenge us to innovate and devise new operating plans. Throughout the year, we continued to execute our core business goals and accelerated our transition to a low-carbon future.

In 2008, the Public Utilities Commission of Ohio approved our save-a-watt energy efficiency and smart grid programs. These initiatives redefine the boundary between our utility equipment and our customers' home and business power networks. In the past, utility service stopped at the meter. No longer. Under the save-a-watt and smart grid programs, we will work with our customers so they can use their energy more efficiently and productively — while reducing their monthly bills.

Last year, we proposed a program that would install photovoltaic solar panels on the [illegible] of up to 400 North Carolina homes and businesses, one of the first such distributed generation ventures in the nation. Together, these units would generate enough power to supply about 1,300 homes. This project could help us to gain experience in installing and operating these on-site electricity generation facilities.

We believe our nation can't achieve significant reductions in its carbon emissions without building new nuclear energy capacity, which emits zero greenhouse gases. We have filed an application for a combined construction and operating license with the U.S. Nuclear Regulatory Commission for a potential new nuclear station — the William States Lee III station in South Carolina. Although a final decision to build a new nuclear station is still in the future, work must continue to ensure this option remains available to meet the growing demand for electricity.

These and other projects are shaped by our over-arching goal: to develop a capital-efficient and environmentally advanced energy system that provides customers with affordable, reliable and increasingly clean energy.

Additionally, we are focused on achieving our low-carbon 21st century goals. In light of that, we are working with influential regulatory, technological and environmental thought leaders. In these partnerships, we examine what needs to be changed and what doesn't. You will meet three of these thought leaders later in this report. Their experience and knowledge are vital to successfully navigate our transition.

For the third year in a row, Duke Energy was named to the Dow Jones Sustainability Index (DJSI) for North American companies in the electric utility sector. In March 2009, Corporate Responsibility Officer magazine named Duke Energy to its 100 Best Corporate Citizens 2009 list. This recognition underscores our fundamental commitment to responsibly serve all of our stakeholders. I invite you to also review our 2008/2009 Sustainability Report, available on our Web site, to learn more about the bold stretch goals we have set.

Challenges in 2008

We are used to challenges, but 2008 was a standout year. Due to the deepening recession, our kilowatt-hour sales growth declined in all of our regulated service territories. The [illegible] in the real estate market also continued to impact [illegible] Resources. As a result, we fell short of achieving our 2008 employee incentive target of $1.27 of adjusted diluted earnings per share (EPS).

But importantly, with the combined 2008 adjusted segment earnings before interest and taxes (EBIT) of U.S. Franchised Electric and Gas, Commercial Power and International Energy and our employees' efforts to control costs, we achieved a total 2008 adjusted diluted EPS of $1.21.

Last year, our employees delivered on our most important metric of all: it was our best year ever for employee safety. Our *Total Incident Case Rate*, a common industry standard used to measure safety performance, dropped to 1.15, an 8 percent improvement over 2007. All major operational groups hit their safety targets. Even more importantly, we had no work-related fatalities last year, and serious injuries were down.

Our employees also delivered an excellent year from an operations standpoint. They responded heroically in September when the remnants of Hurricane Ike tore through our Midwest service territory. With about 1.1 million of our 1.6 million customers impacted, this was easily the largest storm-related incident in our history for this region. Despite the widespread damage to our system, we were able to safely restore service to every customer within eight days.

Last year, our stock performance was down but we still outperformed the overall markets. Duke Energy's 2008 total shareholder return was −21.7 percent, compared to −37.0 percent for the S&P 500 and −27.2 percent for the Philadelphia Utility Index. While there is some consolation in out-performing the market in 2008, our goal remains to deliver sustainable growth over the long term.

No one knows just how long this recession will last or how severe it will be. With double-digit national unemployment forecast for 2009, there is a lot of belt tightening going on in homes and businesses throughout the country. At Duke Energy, we will continue to take the necessary steps to maintain our strong balance sheet.

Maintaining Our Liquidity and Cash Positions

Efficient capital attraction and deployment is our lifeblood — it is the key to our future earnings growth. Electric utilities are one of the most capital-intensive of all U.S. industries. During the unprecedented tightening of the credit markets in 2008, we continued to access capital markets.

From Jan. 1, 2008, through Jan. 31, 2009, we issued about $4.5 billion of fixed-rate debt at a weighted average rate of 6.05 percent with an average maturity of 15.1 years. To put this in context, it should be compared with the weighted average cost of our total long-term debt at year-end. For 2008, year-end cost of our total portfolio was 5.65 percent, with an average maturity of 12.7 years. We also [illegible] investment-grade credit ratings.

We will continue to allocate cash to our growth projects as well as to maintain and grow our dividend. We are proud that 2008 was the [illegible] consecutive year that Duke Energy paid a quarterly cash dividend on its common stock. Last year, the Board of Directors increased the quarterly dividend payment from 22 cents to 23 cents per share.

Investing in the Future

We have the potential to invest nearly $25 billion over the next five years to modernize our regulated operations and to grow our commercial businesses. About $7 billion is committed capital, including the dollars allocated for completing our two new advanced coal-fired plants. Roughly $13 billion is for ongoing capital spending, such as maintenance, which has some flexibility as to when it is spent. The remaining $5 billion of our potential investment is discretionary growth capital. We won't invest these discretionary dollars unless 1) we secure constructive regulatory treatment for projects in our regulated businesses, or 2) our return expectations are met for projects in our commercial businesses.

We believe we can grow earnings through more creative legislative and regulatory frameworks — such as save-a-watt approval and cash recovery of construction work in progress. This will allow us to recover financing, construction and energy efficiency costs on a timely basis to earn fair and competitive returns on capital over time. As a result, we remain committed to growing adjusted diluted earnings per share at a compound annual growth rate of 5 to 7 percent through 2013, assuming a rebound in the economy.

An Evolving Mission

Today, the electric utility industry is at a crossroads. Energy policies over the 20th century promoted investment in large generating plants fueled by low-cost fossil fuels, primarily coal and natural gas. They also fostered the development of nuclear power. The success of this effort was essential to the United States' emergence as a world economic superpower.

With the mission of providing universal access to electricity accomplished, we face new challenges. Our mission for this century is to redefine our boundaries — to go beyond the meter, creating new customer partnerships and providing universal access to clean and efficient energy.

To accomplish this mission we are:

1. Promoting investment in customer programs to accelerate the contribution of energy efficiency to meet future demand;
2. Building a new fleet of efficient power plants using diverse fuels to meet growing demand and to increase our reliability, while retiring older, higher-emitting plants to significantly decrease our environmental impact; and
3. Pushing for the approval of legislative and regulatory policies that will ease the transition to an industry with significantly lower [illegible] emissions.

Our mission for this century is to redefine our boundaries — to go beyond the meter, creating new customer partnerships and providing universal access to clean and efficient energy.

GOING BEYOND THE METER:

Promoting investment in customer programs to accelerate the contribution of energy efficiency to meet future demand.

We consider energy efficiency to be our "fifth fuel." Of course, it's not like water, coal, natural gas or uranium. You can't touch or smell energy efficiency, but you can understand why it is vital to our future. By making our entire system more efficient, we will save money because we will need fewer power plants. At the same time, we will maintain high-quality service and reliability.

However, existing regulations create disincentives for investing in energy efficiency. Most utilities earn returns on capital only when they build new plants. But regulators, such as those in Ohio, are shifting this paradigm. The save-a-watt model they have approved helps create a level playing field for energy efficiency and investments in new plants.

The new model promotes energy efficiency investments by allowing us to recover the money and earn a return on the savings realized by *not* having to build a new plant. This is called the "avoided cost."

Everyone wins under this new program. Our customers win because they save money from increased energy efficiency. Investors win because the returns they earn on efficiency investments are comparable to those earned by investing in a new plant. Society and communities win because we will need to build fewer power plants, which will reduce emissions including greenhouse gases. As a result, customers as a whole will enjoy even more reliable power and new time-saving services and conveniences.

The Save-A-Watt Model

Save-a-watt is entirely performance-based. If the investments in more efficient lighting, heating and cooling systems don't save energy — which will be verified by an independent third party every year — we don't get paid. Customers who participate directly in the programs could see their bills go down on average by about $5 per month.

We filed our save-a-watt plan in Kentucky in December 2008. In early 2009, South Carolina regulators rejected our save-a-watt plan, but we expect to re-file, as they showed strong support for energy efficiency and a willingness to expedite their review of a revised plan. North Carolina regulators requested additional information on our save-a-watt filing, but they also approved our proposed energy efficiency programs. In late February and early March 2009, Indiana regulators held hearings on save-a-watt. We expect an order later in 2009.

Modernizing Our Distribution System

To fully benefit from our save-a-watt investments, we need to upgrade our transmission and distribution system. Our nation's power grid has used the same analog switches, controls and meters for more than 100 years. This equipment has served us well, but it will not be adequate to connect to new energy-efficient smart appliances and equipment. This requires a digital two-way interconnection — a "smart grid." When this technology is in place, our customers will be able to manage their appliances and equipment more efficiently.

Over the next five years, subject to constructive regulatory treatment, we plan to invest about $1 billion in smart grid equipment in homes and businesses. By mid-2009, we will have installed more than 70,000 smart electric meters in three states and about 40,000 digital gas meters in the Midwest. As I noted earlier, we have received approval to begin the deployment of smart grid technology in Ohio, including installing 700,000 smart meters over the next five years. We are also seeking approval to install up to 800,000 smart meters throughout our Indiana service territory.

Maintaining Customer Comfort and Convenience

Smart grid technology will give our customers the opportunity to optimize their energy consumption while we more efficiently manage our overall generation load. For example, digitally connecting appliances such as air conditioners, water heaters and dishwashers to smart meters allows these devices to be programmed to briefly turn off and on during times of peak demand. This will better balance our loads and, in turn, save customers money.

Our obligation to meet the needs of our customers for affordable, reliable and increasingly clean energy cannot be fulfilled without coal in our fuel mix. Building more efficient and cleaner coal units and retiring older ones serves as a bridge to the future.

These systems are largely invisible. There is no sacrifice in comfort or convenience. In fact, some customers in ongoing pilot programs didn't realize these systems were even operating until they saw the associated cost savings on their electric bills. Eventually, customers who want more control over their energy consumption and savings potential will be able to view their real-time energy usage through an energy portal that can be displayed on a home computer, a television set or a smart phone.

We expect to achieve similar efficiency improvements and savings on our side of the meter. These investments will allow us to automatically balance loads and isolate overloads to prevent outages.

Visiting the Future

In 2008, we opened our Envision Center in Erlanger, Ky., just a few miles from our Ohio offices. Here our stakeholders can experience the 21st century utility firsthand. Visitors learn about many energy management devices, including smart meters, storage batteries, solar panels and other emerging technologies.

The center includes our "smart garage," where plug-in hybrid electric vehicle manufacturers offer demonstrations of their prototypes. As you will see on page 16 of this report, I've visited the center and you should, too — it brings energy efficiency and the smart grid to life.

We've since opened our second Envision Center in Raleigh, N.C., and we are field-testing some of these new technologies at a subdivision in Charlotte, N.C.

Along with our smart meter initiative, these demonstration sites are providing us with real-time experience to make sure the homes, businesses and communities we serve are significantly more energy efficient.

Envision Center
By Duke Energy

MEETING FUTURE NEEDS THROUGH SUPPLY:

Building a new fleet of efficient power plants using diverse fuels to meet growing demand and to increase our reliability, while retiring older higher-emitting plants to significantly decrease our environmental impact.

We take our responsibility for meeting our customers' needs in a sustainable way very seriously. As proof, consider that today we are the third largest generator of electricity among the top 20 U.S.-based investor-owned utilities. Not surprisingly, we also rank third in this group for total tons of carbon dioxide (CO_2) emitted. However, when you look at carbon intensity, which is simply the amount of CO_2 emitted per unit of energy produced, based on the latest available 2007 data, eight other companies within this group had higher carbon intensities than we did.

As we transition to a low-carbon future and grow our system to meet future demand, carbon intensity will be a good way to judge our progress in decarbonizing our generation fleet.

Replacing Old Coal with New Cleaner-Burning Coal Technologies

Why are we building coal and other fossil fuel plants if we want to lead in energy efficiency as well as in reducing greenhouse gas emissions? The answer is simple: Our obligation to meet the needs of our customers for affordable, reliable and increasingly clean energy cannot be fulfilled without coal in our fuel mix. Building more efficient and cleaner coal units and retiring older ones serves as a bridge to the future.

To put it another way, we don't know what inventor working in his or her garage might come up with a "silver bullet" invention to control carbon emissions — or if anyone ever will. To hedge this uncertainty, we've adopted a "silver buckshot" strategy. We are [illegible] power supply options with a diverse portfolio that includes clean coal, nuclear, natural gas, renewables and energy efficiency. This balanced approach [illegible] availability and [illegible] volatility [illegible] fuel.

Just over 50 percent of our regulated generation capacity is fueled by coal. In the Midwest, approximately 95 percent of our energy sales come from coal-fired assets. We are building two new advanced coal-fired plants — about a $5 billion investment — to replace older coal units.

At year-end 2008, the new 825-megawatt Cliffside Unit 6 coal project in North Carolina was nearly 30 percent complete. When it is finished in 2012, it will eventually replace more than 1,000 megawatts of older, less efficient and higher-emitting coal units. As we retire older coal units and take other actions, we expect this plant to be carbon-neutral by 2018.

In Indiana, the 630-megawatt Edwardsport coal gasification plant was about 20 percent complete at year-end 2008. When finished in 2012, it will replace 160 megawatts of existing coal units built in the 1940s and 1950s. Importantly, we hope to use developing technology for carbon capture and storage near this plant site. We are seeking a portion of the funds authorized for cleaner coal technologies in the federal stimulus package enacted in February 2009 for this part of the project.

Additionally, we are building two lower-emitting 620-megawatt combined cycle natural gas-fired plants at two existing facilities in North Carolina. When completed in 2012, these new units will retire a total of about 250 megawatts of older coal-fired units as part of the 1,000 megawatts referenced above.

Baseload coal and nuclear power plants are the workhorses of power generation. Unlike wind and solar power, they typically supply power 24 hours a day.

By 2013, when we will have completed our two new coal plants, the two new gas-fired plants and shut down the older units, we will reduce our carbon intensity by roughly 10 percent. If we proceed with the new Lee Nuclear Station and can bring it on line by 2020, we will have reduced our carbon intensity by about 20 percent.

Advancing Renewable Energy

Our utility companies are increasing the amount of renewable energy in their mix to meet both existing and anticipated renewable portfolio standards. Over the last two years, we have issued requests for proposals in the Carolinas, Ohio and Indiana, seeking bids for power generated from solar, wind, water, biomass and other renewable sources. Last year, a new wind farm in northern Indiana began supplying our Indiana customers with up to approximately 100 megawatts of electricity. Our agreement to receive power from this wind farm extends for 20 years.

To ensure that power from a growing number of new wind farms in the Midwest reaches our service territory, we formed a 50-50 joint venture with American Electric Power to site, build and operate a 240-mile ultra-high-voltage 765-kilovolt transmission line in Indiana. Besides linking new and existing generation in the northern and southern parts of the state, the $1 billion project will also help alleviate grid congestion in the Midwest. The earliest possible completion date for the project is 2013.

We also signed a 20-year agreement to purchase the full output of what will be one of the nation's largest photovoltaic solar farms to be built in North Carolina. Construction will begin in 2009, and the facility is expected to be operational by year-end 2010.

Additionally, we have agreed to purchase five megawatts of electricity generated from methane gas from a landfill in Durham, N.C., and one near Greenville, S.C. Producing electricity from methane gas not only uses a renewable fuel, but it also destroys the methane, which has a global warming impact 20 times greater than CO_2.

On the commercial side of our business, we are expanding into biopower with a joint venture with French energy giant AREVA. This new company, ADAGE, will develop plants in the United States powered by wood waste. AREVA will design and build the plants, and Duke Energy will operate and manage them. We are aiming to start construction on the first plant in 2010.

Over the last several years, Commercial Power acquired two wind energy companies, and last year we began operations at our first two wind farms in Wyoming and Texas. We are also co-owner of the Sweetwater project in Texas — one of the largest wind farms in the world.

In a unique agreement with Wal-Mart, beginning in the second quarter of 2009 and for the next four years, our Texas facility will supply wind energy for a portion of the total energy used by more than 350 stores in Texas.

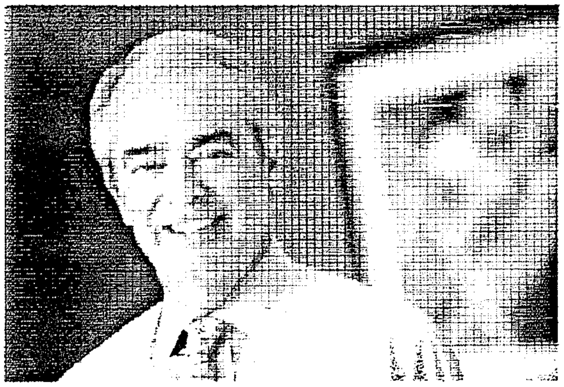
At the end of last year, we had close to 400 megawatts of wind power in operation and a potential wind development pipeline of more than 5,000 megawatts in 14 states.

THE CLIMATE CHALLENGE:

Pushing for the approval of legislative and regulatory policies that will ease the transition to an industry with significantly fewer greenhouse gas emissions.

Long-term investors know that we see climate change as one of our nation's greatest challenges. I believe we need to regulate CO_2 and other greenhouse gas emissions, and we need to do it now. I have been an advocate of a cap-and-trade system to regulate and reduce CO_2 emissions since the beginning of this decade.

Rather than a patchwork of policies focused on a few industries or regions of the country, we are pushing for enactment of federal cap-and-trade legislation applied equally to all parts of the economy, including power generation, manufacturing facilities, commercial businesses and motor vehicles.



To permit the economy to adjust rationally to the policy, legislation should establish a long-term program that first slows the growth of emissions, stops them and then reverses them by creating a gradually declining emissions cap. This will provide the time needed for the development and deployment of new lower- and zero-emitting technologies. Legislation should also include adequate cost containment measures to protect our economy.

Duke Energy is one of the more than two-dozen member companies in the U.S. Climate Action Partnership. Along with environmental and other advocacy groups, we worked for two years to craft a blueprint for action that is workable and fair. It protects consumers by smoothing out the energy price increases that will result from capping carbon emissions. We presented our plan to Congress in January 2009 and we are aggressively pushing for its enactment. I urge you to review it at www.us-cap.org.

A PRIVILEGE TO SERVE

On Oct. 27, 2008, I celebrated my 20th year as a utility CEO. This milestone was possible because I've had the privilege to work over these years with so many supportive stakeholders — our employees, investors, customers, suppliers, bankers, regulators and communities. I am grateful for your continuing confidence. I have also been blessed with great management teams and dedicated board members throughout this time.

One such board member was Mary Schapiro, who served as a director of Cinergy and then Duke Energy since 1999. In December of 2008, she was nominated by President Obama to chair the U.S. Securities and Exchange Commission (SEC). She was unanimously confirmed by the U.S. Senate to that position in January 2009. We miss Mary's insights and thoughtful debate on our board, but we know she will excel at the SEC. We thank her for her 10 years of service to our company.

Judging Our Performance

In this business, we are judged every day when our customers throw their switches and expect power to flow into their lives. We are judged monthly on the affordability of our product when customers open up or download their bills. We are judged by investors when they look up our stock price and receive their dividend checks. We are judged by the communities we serve, who expect us to keep our rates competitive and the environment clean.

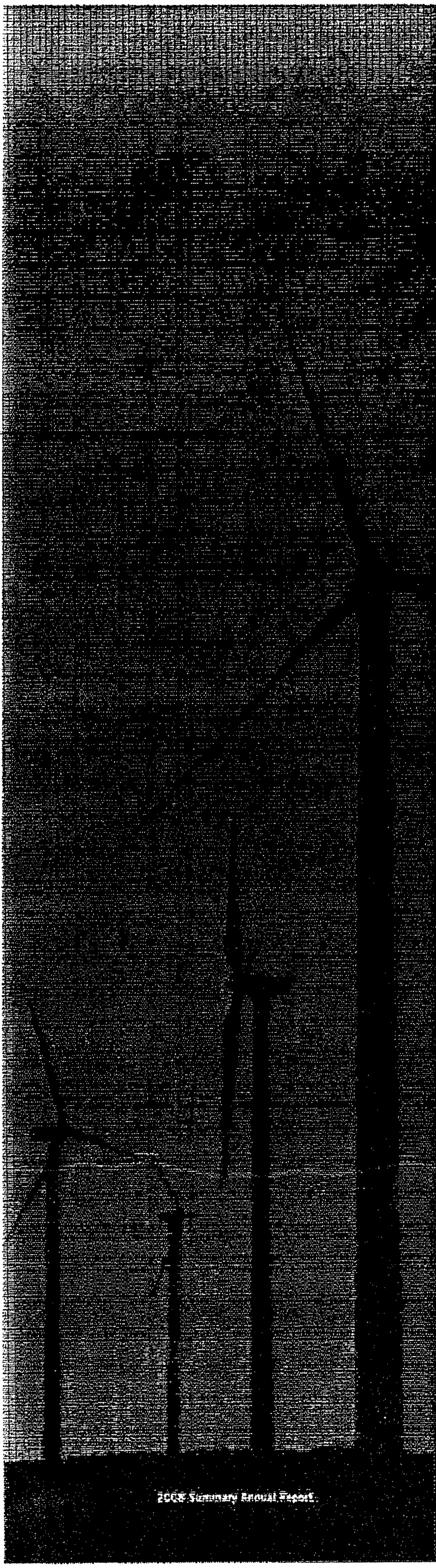
But I think the toughest judgment will come from the future — it's what I call "the grandchildren's test." When my eight grandchildren look back, I want them to understand why we pushed so hard for clean air and climate change legislation, why we introduced innovative plans like our save-a-watt program to save energy and reduce emissions. I want them to know that we always tried to do the right thing.

We live in uncertain times, but our value proposition remains unchanged. We are maintaining a strong balance sheet, investing in the future, and protecting and growing our dividend. I look forward to continuing our journey as we work to redefine our boundaries and meet our challenges. Thank you for your continued interest and investment in Duke Energy.

James E. Rogers

James E. Rogers
Chairman, President and Chief Executive Officer

March 12, 2009



A Changing Mission

The mission of electric utilities 100 years ago was to ensure universal access to electricity for all Americans. With that mission accomplished, the industry's mission for the 21st century is to go beyond the meter to provide universal access to energy efficiency. We must provide energy that is affordable, reliable and increasingly clean. This will drive economic growth and preserve our environment. This requires new ways of thinking about our business.

In the next section we offer interviews with three highly-respected thought leaders to clarify the technological, regulatory and environmental choices we face. These experts remind us that change requires the boldness to redefine our boundaries. Only then can we create a sustainable future for our children and grandchildren.

Redefining **Technology**

An interview with

Larry Makovich

Cambridge Energy Research Associates
Vice President and Senior Advisor
Cambridge, Mass.

Larry Makovich is a highly respected expert on electric power market structures, demand and supply fundamentals, wholesale and retail power markets, emerging technologies, asset valuations and strategies. He directs CERA's research efforts in the Global Power Group and is an authority on electricity markets, regulation, economics and strategy.

DUKE ENERGY: What new technologies do you see coming into the energy space in the next five years, and what impact will they have?

LARRY MAKOVICH: Clearly the technology that everybody's excited about is the smart grid. Duke Energy is among a number of power companies at the leading edge of this innovation.

The smart grid will reshape power demand, deliver greater efficiency and provide things like better security for homes and businesses. It will enable better predictive maintenance capabilities and improved environmental accountability. The smart grid is a near-term technology that's very promising, and it will be exciting to track it over the next five years and beyond.

DE: How does the smart grid work?

LM: A lot of people think the smart grid is just the application of advanced meters. It's a lot more than that, and the biggest impact of this innovation isn't going to come from just a single metering or measurement technology. It's going to be a combination of measurement devices, sensing technologies, information technology, communication technology and other things like nanotechnology and optimization software. I think that within five years a smarter grid will fundamentally change the way electric customers interact with their suppliers.

DE: How can the traditional cost-of-service regulatory utility model survive? How can it be moved into the 21st century to promote the benefits of new technologies?

LM: Regulations have always focused on traditional electric service, which is often just measured in kilowatt-hours of energy consumed or megawatts of peak demand. When you think about the future and these expanding boundaries, regulators will have to think about regulatory structures that support efficiency gains. Importantly, regulations ought to evolve to provide the same kind of positive incentive to reduce power demand as they currently do to increase power supply.

For instance, regulators will have to come up with ways to deal with the economics of solar panels and other forms of distributed generation. This revolution will allow customers and the utility to rely on the grid as a virtual battery that they can put surplus power into when they've got it, and take energy out of when they need it. There are going to be new functions and new capabilities beyond the traditional products. Regulators will have to define and allow for cost recovery of these products and programs. This will ensure that power suppliers evolve and grow at the same pace as new technology development.

DE: We're in a period of rising energy prices. We're in a recession and Congress may pass climate legislation in 2009 or 2010, which will further impact energy prices. As an industry, how do we leverage technology while keeping prices affordable?

LM: It is a challenging environment. The real price of electricity has been increasing in this country for several years. There's no one thing — whether it's a push for more renewables, a push for more efficiency or a push to put a price on carbon — that's going to be the straw that breaks the camel's back. All of them are creating upward momentum for power prices. That puts a premium on the need for very intelligent federal and state rules and regulations to accomplish these goals efficiently and cost effectively. Left uncoordinated, accumulated costs will drive up energy prices to levels that are politically intolerable.

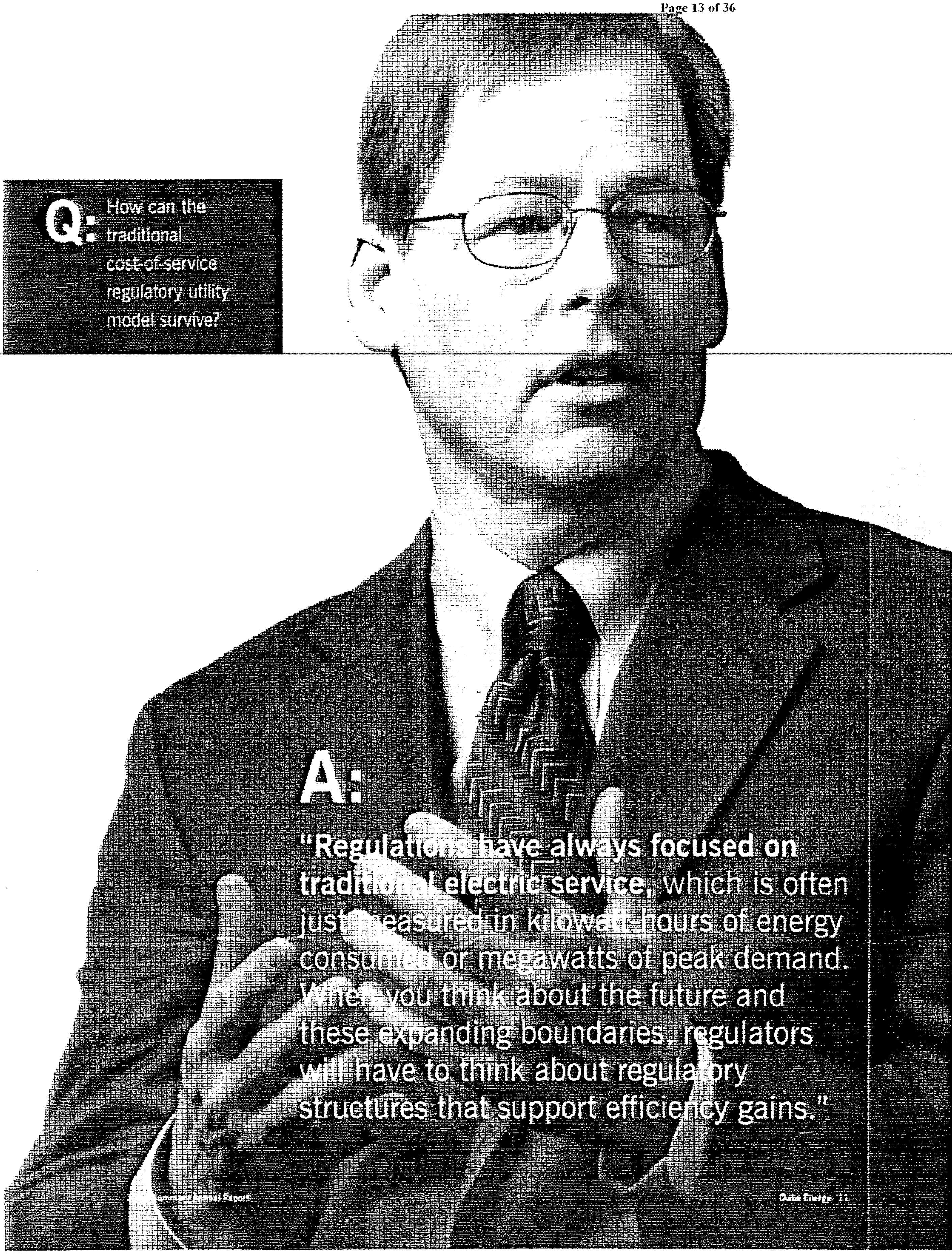
DE: In your view, is scale important to promote new technologies?

LM: Companies need the critical mass to sustain the experimentation and deployment of new technologies. They have to be big enough to partner with universities and labs to work together to do basic research and extend innovations into power applications. They need to team up with regulators to implement pilot programs to gain the experience and knowledge needed to roll out new technologies for all of their customers.

Companies that can help create clusters of basic research and development, engineering applications and regulatory support, and integrate them into their existing business, will be the ones that sustain themselves in the future. Research Triangle Park in North Carolina is a good example of one of these clusters.

For more of Larry Makovich's interview, go to [illegible]

Q: How can the traditional cost-of-service regulatory utility model survive?



A:

"Regulations have always focused on traditional electric service, which is often just measured in kilowatt-hours of energy consumed or megawatts of peak demand. When you think about the future and these expanding boundaries, regulators will have to think about regulatory structures that support efficiency gains."

Redefining **Regulation**

An interview with

Kateri Callahan

Alliance to Save Energy
President
Washington, D.C.

Kateri Callahan brings more than 30 years of experience in public advocacy, fundraising, coalition building and organizational management to her position as president of the Alliance. Under her leadership, the Alliance conducts policy, communications, research, education and market transformation initiatives in the United States and more than a dozen other countries.

DUKE ENERGY: Why the sense of urgency around energy efficiency?

KATERI CALLAHAN: The urgency to deploy energy efficiency at an unprecedented level couldn't be greater. Even with the current recession, we are still faced with projections of increased electricity use in the United States of nearly 30 percent between now and 2030 — only 22 years.

To meet that demand, utilities are going to have to put new power plants into their plans. New power options aren't great and they come with a heavy price no matter what you pick. If by using energy efficiency we can delay building a new power plant, for one, two or three or more years — or perhaps forever if we're really good at it — that helps us tremendously.

DE: Do rising then falling energy prices remove that urgency?

KC: I was concerned that the downturn in the price of gasoline would lessen the interest of policymakers and the public in moving forward on energy efficiency and that we would get lulled back into complacency — much as we did after the first energy crisis resulting from the oil embargo in the early '80s. But I don't see that happening. I think that there is "steel in the spine" of policymakers now and they understand that we've got to tackle our energy-related problems. We just can't afford to once again slip into complacency.

DE: What do you think of Duke Energy's save-a-watt model?

KC: What we like about it is that Duke is committed to do all cost-effective energy efficiency — and to determine what that means with an advisory council comprised of local stakeholders, regional stakeholders and folks at the national level who are committed to energy efficiency.

The second thing is that Duke has agreed through its model, and through a memorandum of understanding with us and other national stakeholders, to invest in state-of-the-art evaluation, measurement and verification programs to ensure that the promised energy savings are actually delivered.

The third, and probably most important thing, is that Duke will be allowed to make a profit on energy efficiency investments just as they do on conventional capacity. That's really the key to getting utilities to invest in energy efficiency. To have them only made whole or worse still to penalize them for investments in energy efficiency versus investments in capacity simply doesn't make sense in today's environment.

DE: What other key benefits do you see from the save-a-watt approach?

KC: In many of the energy efficiency programs being undertaken around the country, there's not as much transparency as we would like to see. With its proposed third-party review and oversight, the save-a-watt model has that transparency.

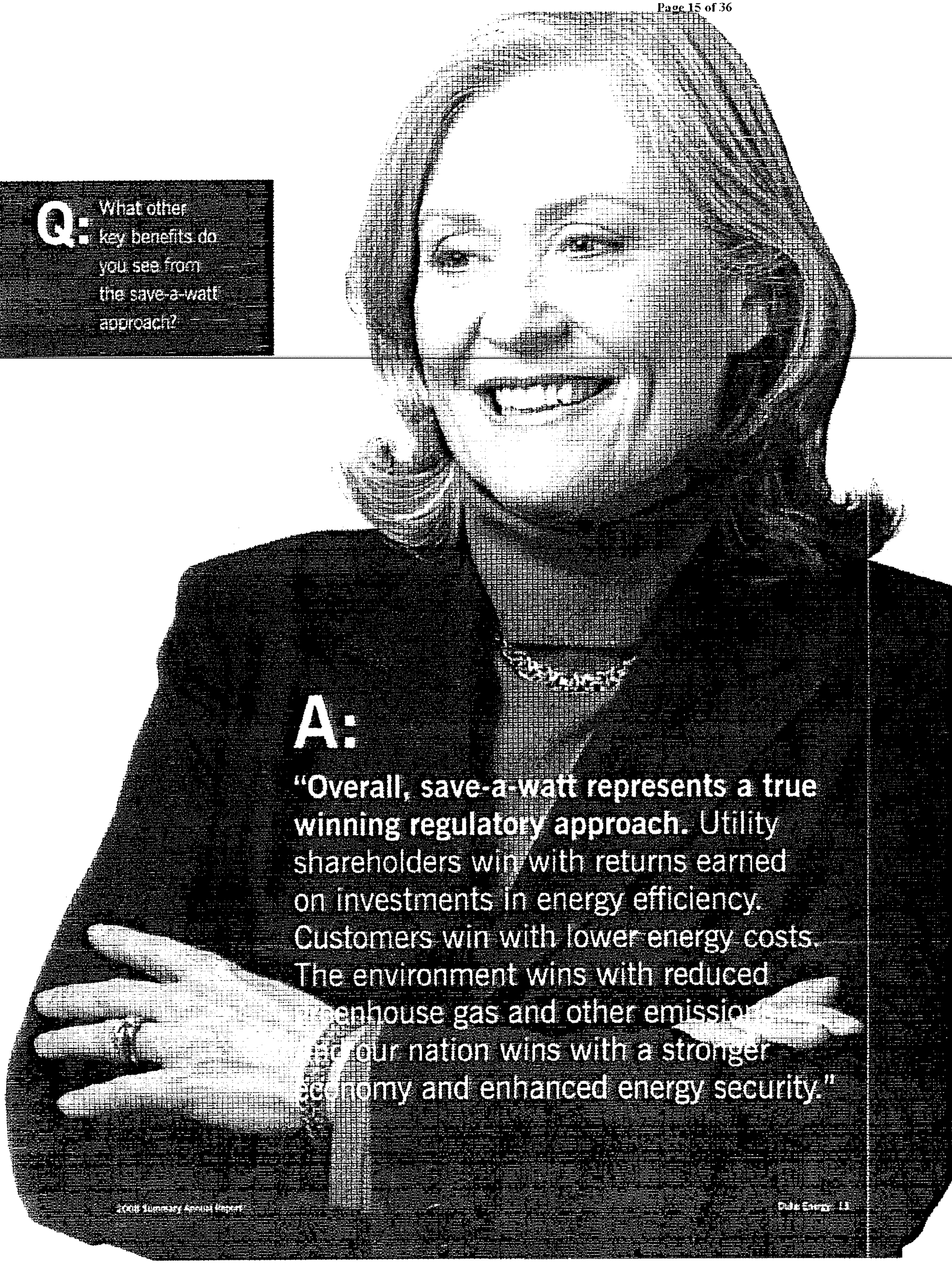
Overall, save-a-watt represents a true winning regulatory approach. Utility shareholders win with returns earned on investments in energy efficiency. Customers win with lower energy costs. The environment wins with reduced greenhouse gas and other emissions. And our nation wins with a stronger economy and enhanced energy security.

DE: What should regulators do to encourage the research, development and deployment (RD&D) of new technologies that would benefit energy efficiency?

KC: If regulators would allow utilities to earn a profit on energy efficiency — just as they do already on conventional capacity — this would be incredibly useful in driving utility investments in clean tech and green tech, not only by utilities, but also by technology developers and entrepreneurs.

The Alliance to Save Energy is also pushing hard at the federal level to double federal investment in energy efficiency RD&D. My hope would be that those dollars could spur greater investment by utilities in partnerships between the government and industry, and that the regulatory commissions would see the value of allowing utilities to participate and leverage federal and state dollars. Investing in energy efficiency will help spur investments in renewable energy and help make it more cost-effective.

For more of Kateri Callahan's interview, go to www.duke-energy.com or



Q: What other key benefits do you see from the save-a-watt approach?

A:

"Overall, save-a-watt represents a true winning regulatory approach. Utility shareholders win with returns earned on investments in energy efficiency. Customers win with lower energy costs. The environment wins with reduced greenhouse gas and other emissions. And our nation wins with a stronger economy and enhanced energy security."

Redefining **Climate Legislation**

An interview with

Fred Krupp

Environmental Defense Fund
President
New York, N.Y.

Fred Krupp is widely recognized as the foremost champion of harnessing market forces for environmental ends. This approach has become the leading model for solving global warming. In his 24 years as head of EDF, Krupp has overseen EDF's growth from a small nonprofit into a recognized world-wide leader in the environmental movement.

DUKE ENERGY: How do you view Duke Energy in terms of the way it is trying to redefine its boundaries to address climate change?

FRED KRUPP: I appreciate Duke taking a constructive role in searching for answers and solutions on national climate policy. We know we're going to disagree on some things, but the idea that here's a company that's willing to join the voices of leadership on this issue and say, "Yes, this is how we can do it," instead of the more typical, "No, let's stand pat," is very much appreciated.

DE: What should be the role of companies like Duke Energy in meeting the climate challenge?

FK: As one of the nation's largest emitters of greenhouse gases, Duke Energy has an obligation to be engaged in finding and implementing solutions to the problem. The decisions you make every day about what plants to run and what plants to build are decisions that will have implications for generations.

What I've appreciated in Washington is that companies like Duke can be a powerful voice for change, and Jim Rogers' participation in the U.S. Climate Action Partnership and support of its Blueprint for strong legislation, have helped open the eyes of legislators to the urgent need for action.

DE: In your opinion, what are the minimum requirements for federal climate legislation?

FK: Any climate legislation needs to be a cap-and-trade program that starts with a mandatory declining cap that gets us 20 percent reductions in the nation's emissions by 2020, 42 percent reductions by 2030 and 80 percent by 2050.

DE: How should such legislation address energy efficiency and the technology options of carbon capture and storage?

FK: In the near term, there's a lot to be gained from investing in energy efficiency, as the cleanest power plant is the one we don't have to build — where every dollar we spend stays at home.

One of the reasons that I believe those who care about the environment should be supporting carbon capture is because if we can make it viable, we raise our ability to lower carbon emissions much faster than otherwise by cutting emissions from existing power plants.

In terms of nuclear energy, the fact that climate change is so severe means that we can't afford to rule out any lower carbon source of energy, including nuclear. But before we consider expanding the use of nuclear power, we need to solve the real problems of waste disposal, security and cost.

DE: Do you think we'll have climate legislation in time for the Copenhagen Climate Conference this December, or is 2010 more likely?

FK: I think we've got a good chance to get legislation in 2009. The big new factor is we now have a president who not only believes we need climate legislation for the sake of the climate, but he understands we need climate legislation for the sake of the economy. That makes me believe it could get done this year, but it will take much hard work to make it happen.

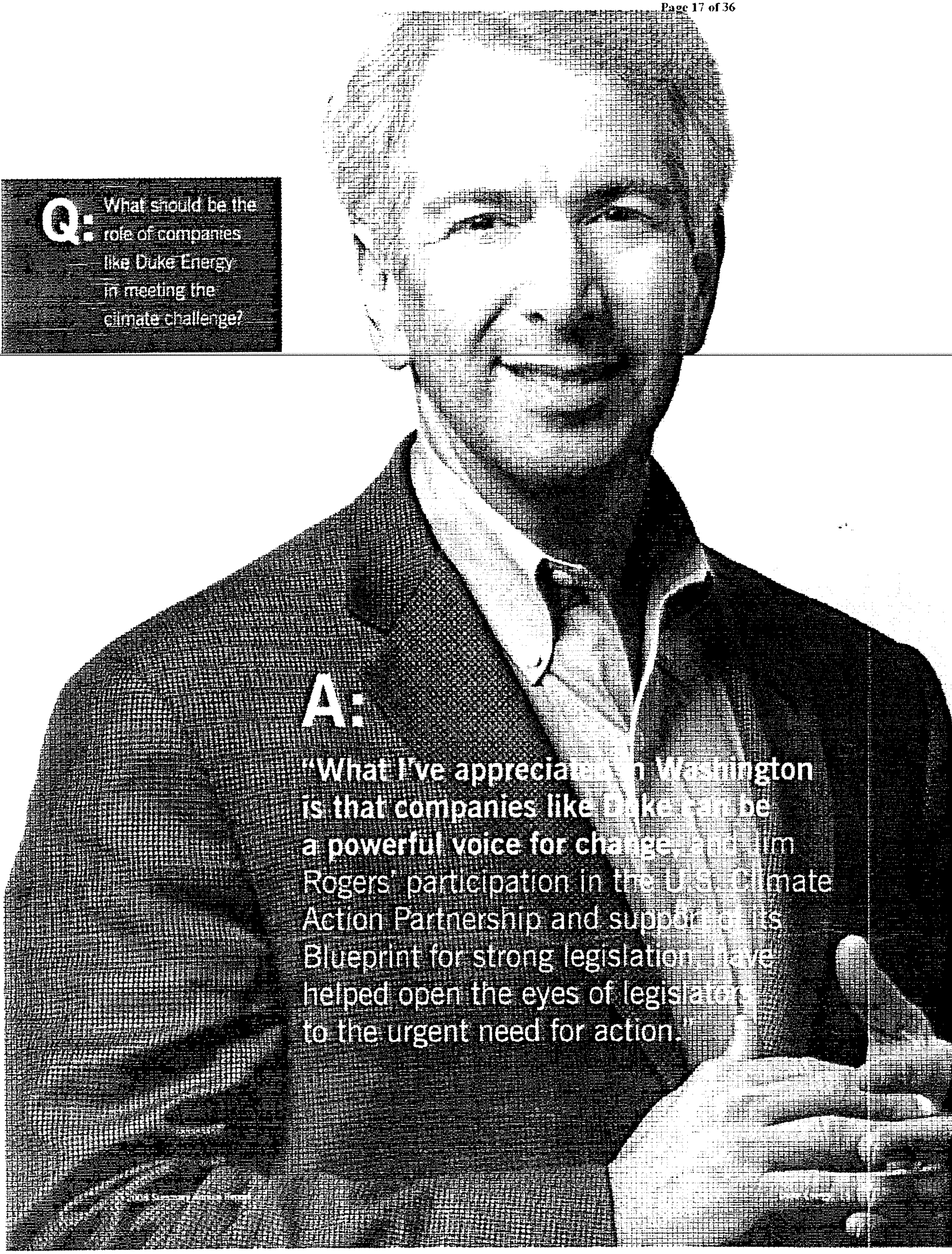
DE: How should such legislation protect consumers, especially those in the two dozen or so states whose electricity is primarily generated from burning coal?

FK: It's important in the transition to a low-carbon economy that we treat all consumers, including consumers in states that are now heavily dependent on coal, in an equitable way to ease the transition.

DE: How can we better educate consumers about how such a market-based system would work?

FK: Any solution starts with firm limits on global warming pollution. A market solution implements these legal limits in a way that rewards innovators so we create jobs, it protects the public at the lowest cost, and has real regulation of the market that achieves healthy air.

For more of Fred Krupp's interview, go to www.duke-energy.com/ar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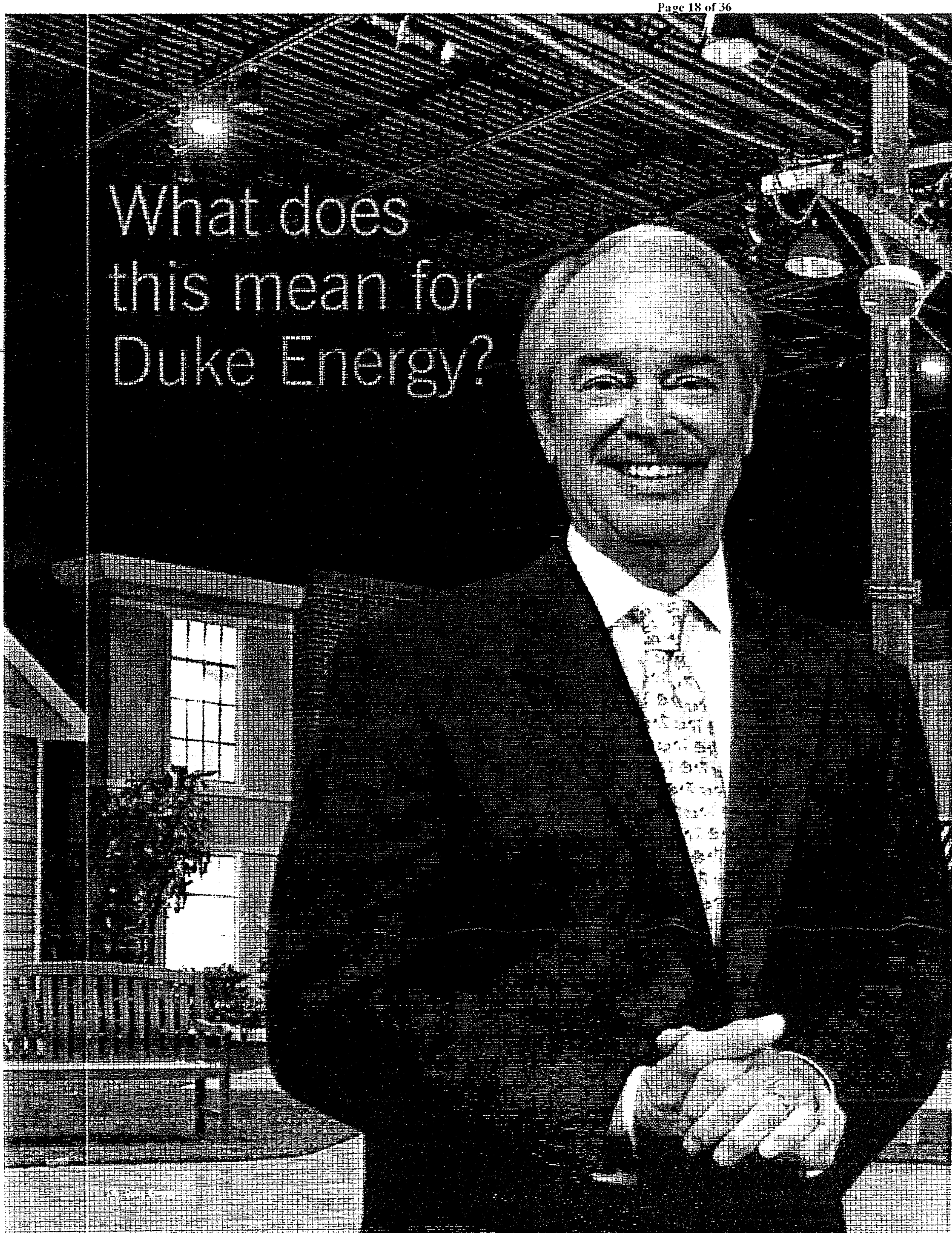
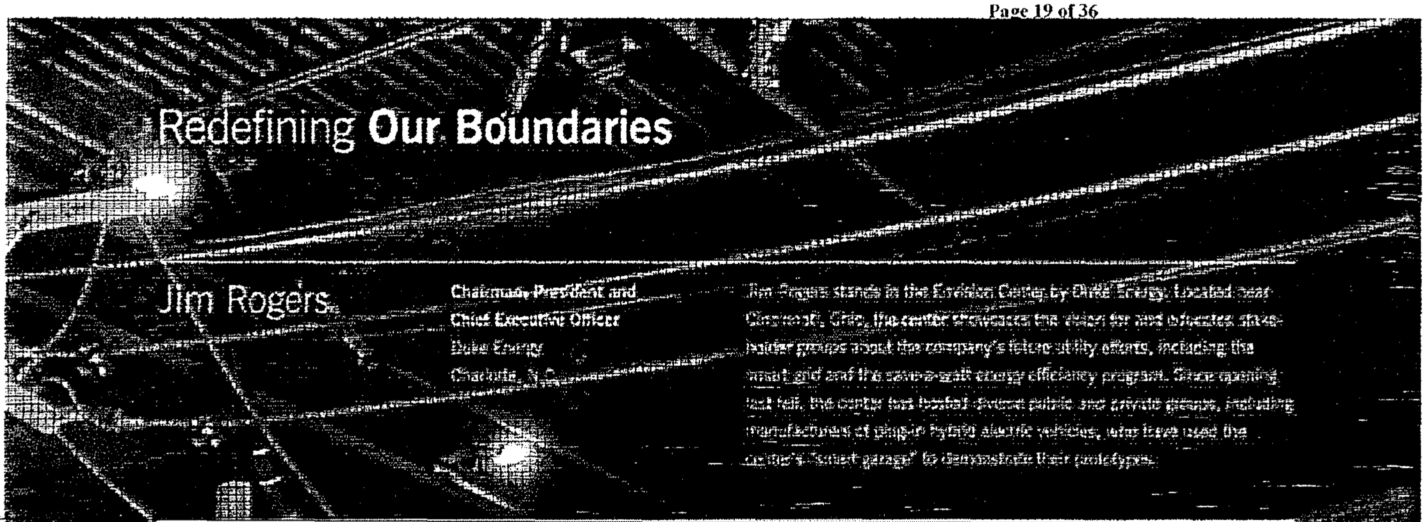

What does
this mean for
Duke Energy?



Redefining **Our Boundaries**

Jim Rogers

Chairman, President and Chief Executive Officer
Duke Energy
Charlotte, N.C.

Jim Rogers stands in the Envision Center by Duke Energy. Located near Cincinnati, Ohio, the center showcases the vision for and educates stakeholder groups about the company's future utility efforts, including the smart grid and the save-a-watt energy efficiency program. Since opening last fall, the center has hosted diverse public and private groups, including manufacturers of plug-in hybrid electric vehicles, who have used the center's "smart garage" to demonstrate their prototypes.

The interviews on the preceding pages illustrate the importance of diverse *perspectives in exploring* ways to redefine our boundaries and successfully transition to a low-carbon *future.* I'd like to discuss what the insights of these leaders mean for Duke Energy. Let's consider them in the context of the two key aspirations I described in last year's summary annual report:

1. Modernize and decarbonize our generation fleet, and
2. Help make the communities we serve the most energy efficient in the world.

Twenty years from now, when our children and their children look back at energy efficiency, they will probably marvel at some of the ways we tried to save energy, including using compact fluorescent light bulbs, caulking windows and installing insulation. Today, the policies we propose and new technologies we develop to further energy efficiency are designed to achieve one goal: to ease the transition to a new energy-efficient society in which future generations can thrive and raise their families.

As Larry Makovich noted (on page 10), technology is key to achieving greater *energy efficiency* in the future. But we must not lose sight of our near-term mission: to help our customers better monitor and manage their energy use in their homes and businesses. To do this, we will partner with our customers by installing sensors, switches and other devices on their appliances and equipment, and also help to write the software to operate this equipment.

But as we develop new technologies, it is essential that we remain flexible. Unlike other current smart grid programs, our plan doesn't focus exclusively on the meter. Sure, advanced metering is essential to greater energy savings, but we view the smart meter as only one of the many "endpoints" for providing more energy information for customers. We're also working with our partners to keep technology standards open to allow plug-and-play compatibility with equipment across multiple systems.

Recently, the Gridwise Alliance, a consortium of public and private stakeholders, acknowledged Duke Energy in a report. The group, which is dedicated to modernizing our nation's electric grid, applauded our comprehensive efforts to fully integrate advanced metering and smart grid technologies.

As Kateri Callahan observed (on page 12), we also need a new regulatory model to realize our children's and grandchildren's legacy. This system must give us the right energy efficiency incentives for customers and provide a fair return on capital investments for investors.

That's the goal of our save-a-watt model. It will provide incentives to create energy efficiency similar to incentives we have to build new power plants to meet growing customer demand for electricity. Using this approach, we would earn revenue based on a discounted amount of what it would cost us to build an equivalent amount of new generation.

Our customers save money, our investors earn a return and there is no environmental impact because, with the increase in energy efficiency, we don't need to build a new power plant.

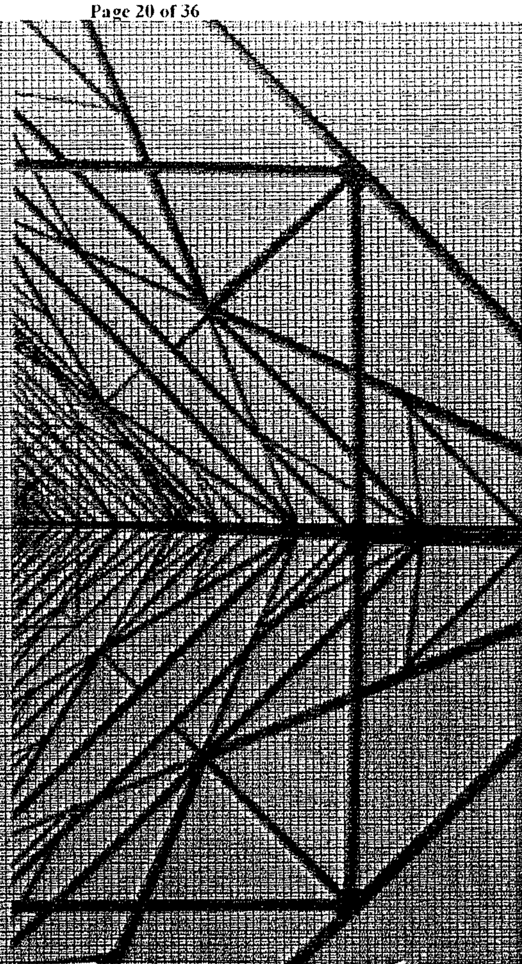
Finally, as Fred Krupp commented (on page 14), we stand a good chance of seeing federal climate change legislation pass in 2009. It is vital that such legislation treats all sectors of the economy fairly. To effectively stem carbon emissions without further weakening our economy, legislation must provide for significant investments in the research, development and deployment of new lower-emitting technologies.

While that is going on, we must be able to expand our use of cleaner coal, nuclear, natural gas, renewables and energy efficiency to meet the increasing demand for electricity. Keeping everything in the mix gives us the time we need to decarbonize and modernize our generation fleet for a carbon-constrained world, and without huge price hikes for our customers.

Next up is a glimpse of how we are redefining our business model to address these 21st century challenges. You'll also meet several of our employees who are working to achieve our two key aspirations above.

Redefining
our business value

Duke Energy exists to provide our customers and communities with energy that is affordable, reliable and increasingly clean, and to create value for our investors. To continue to do this in a carbon-constrained world requires that we redefine the boundaries of our current business model to creatively respond to the challenges of a more environmentally conscious future.



Transforming the way we do business

We are transitioning our company from a traditional power system to one based on more efficient capital and energy use, and with significantly less environmental impact. These pages illustrate the dynamic nature of this transition and the realities of the business boundaries we are working to redefine, as we remain focused on our core business.

Energy Services

From 12 one-way meter information points (monthly bills) per year to more than 35,000 two-way information points via "smart metering." Real-time data is used by both customers and Duke Energy to increase energy efficiency and better balance supply and demand with improved load forecasting.

Fuel

From approximately 70 percent fossil fuels (regulated generation mix) as we evolve to a greater mix of renewable energy, including wind, solar and biomass, as well as nuclear energy and energy efficiency.

Redefining Duke Energy

Generation

From mostly fossil and nuclear plants, to increased energy efficiency to avoid building new plants. Enhanced ability to meet future customer demand with cleaner coal, the retirement of older fossil units, distributed generation, new nuclear capacity and energy efficiency. Commercial businesses transition to being primarily a supplier of renewable energy.

Transmission

From a constrained grid in parts of our service territory to a modernized and expanded grid, with increased capacity to connect rapidly growing sources of renewable energy, especially new wind energy capacity, to our system.

Distribution

From an unintelligent grid to a smart grid that enables enhanced customer service and increases energy efficiency by enabling us to go beyond the meter. The grid transitions to become a two-way information network — an energy Internet — that will be the basis for future networks.

Redefining Our Business Value

Duke Energy employees are working on numerous fronts to create a responsive, efficient and sustainable 21st century company. The following highlights some of their progress on the technological, regulatory and legislative fronts.

Technology Focus

You may not associate technology research and development with a utility. But to increase energy efficiency while reducing operating costs and emissions, research and development (R&D) is a major focus at Duke Energy. We are using technology R&D to redefine how to better balance energy supply and demand, how we can deploy more renewable energy on our system, how our grid can become smarter and how coal can be burned more cleanly to generate electricity.

As an example, in our transmission and distribution systems, we are experimenting with new energy storage technologies. Technology advances have reduced battery size while increasing their storage capacity, efficiency and safety. This means we could eventually deploy high-capacity batteries at our electrical substations and connect them to solar panels and other renewable energy sources. Smaller batteries and storage devices could also be deployed in homes and businesses.

Connected to a smart grid, these devices would help smooth out the peaks and valleys in the daily electricity demand curve. Installed in 10,000 homes, they could also serve as a virtual power plant — distributed resources functioning like a single power plant — supplying power back to the grid during periods of both high and low demand. Such an intelligent infrastructure will be needed for recharging the growing number of plug-in hybrid electric vehicles coming on the market, as well as for all-electric cars and trucks in the future.

We plan to test such a system in 2009 in a pilot project at one of our substations in Charlotte, N.C. At our McAlpine Creek substation, we will install a state-of-the-art 500-kilowatt battery and a 50-kilowatt photovoltaic solar panel array. This equipment will provide supplemental power to about 100 homes equipped with smart meters and power-use sensors. Some homes may also have their own storage batteries.

Inside the homes, the large power-using appliances — such as furnaces, air conditioners, water heaters and clothes dryers — will use plug-in energy-sensing devices that wirelessly connect them to an intelligent gateway. The gateway device is about the size of a hardback book and looks like a cable modem. It enables the customer to monitor and adjust power use through an energy portal displayed on a personal computer, a wireless PDA, a smart phone or a digital TV set. The information from the gateway also gives us the capability to optimize our demand load across the connected homes.

We can optimize load during peak demand times by remotely cycling appliances off and on at short intervals, and use the batteries and the solar array to feed power back to the grid when necessary. In essence, we have created a virtual power plant. And just as electricity [illegible]

Anuja Ratnayake
Manager,
Strategic Initiatives, Technology Assessment & Applications
Charlotte, N.C.

Redefining technology development and deployment

Anuja Ratnayake works in Duke Energy's technology monitoring and adoption group, which is responsible for evaluating new or existing technologies that Duke Energy hasn't previously used. Her focus is on both sides of the meter. She looks at and evaluates advanced technologies on the transmission and distribution side, and then on the customer side — focusing on end-user energy efficiency. Anuja has been with the company for more than four years.

The impact on energy efficiency [illegible] [illegible] on their comfort and convenience. In fact, in other areas where the technology is in use, customers often aren't even aware of it until they see the savings on their monthly electric bill.

This grid optimization project is just one way we are using new technologies to go beyond the meter — to create new partnerships with our customers to significantly increase energy efficiency and reduce our environmental impact.

Unlike other regulatory approaches to energy efficiency, save-a-watt ensures customers only pay for actual reductions in energy use because all programs undergo a rigorous third-party process to verify their energy savings.

Under more traditional regulatory models, customers pay for energy efficiency programs, regardless of whether they achieve the intended results. If power has to be sourced to compensate for a shortfall in energy efficiency, customers end up paying twice — once for the energy efficiency programs and again for the cost of the power. But under the save-a-watt model, the utility takes the risk: If the intended energy efficiency results aren't achieved, the customer doesn't pay.

Regulation Focus

Imagine a regulated utility where customers are charged for the value they receive instead of the costs incurred. In such a world, utilities would focus on lowering their costs and delivering valuable services to customers. If the services don't produce value, the customer doesn't pay.

This is the basic premise behind Duke Energy's innovative save-a-watt approach to energy efficiency. It is a fundamental shift away from the traditional cost-of-service model, focusing instead on a value-of-service regulatory model. Under save-a-watt, Duke Energy must ensure that its energy efficiency programs produce value in the form of verifiable energy reductions in order for the company to recover its costs.

This simple concept changes the utility's focus from spending money to creating value for customers. Such a transformation is not simple. In traditional cost-of-service regulatory models, customers pay a charge for every kilowatt-hour they consume. Utilities recover their costs and earn a return for investments in physical assets (such as power plants, poles and meters). But energy efficiency undermines the utility's profitability through reduced sales.

On the other hand, the save-a-watt model provides compensation based on the value created — a portion of the cost avoided from not building new plants. It also provides a comparable return on investments in physical assets.

Because returns are based on customer value and not on how much was spent on the programs, the save-a-watt model ensures that the utility stays focused on lowering costs and increasing energy reductions for customers. This also encourages the utility to develop innovative energy-saving services that will achieve more energy reductions and lower costs for customers.

For example, to increase customer adoption and awareness, we are partnering with major retailers on new energy efficiency products. Furthermore, we're working with local companies to hire additional staff to implement our programs. Customers who participate in the save-a-watt program will save money by reducing their usage. Additionally, all customers will save money because over the long term, the utility will be able to defer building new power plants. Better yet, combining energy efficiency with a smart grid — another Duke Energy initiative (see page 20) — will generate even more savings.

The save-a-watt approach to energy efficiency will help customers save money, create jobs for our economy and reduce environmental impacts. At the same time, it provides utilities with a way to grow their business. It truly is a win for customers, the local community, investors and the environment. Our save-a-watt program was approved by Ohio regulators late last year. We continue to seek its regulatory approval in the other states where we have regulated utility operations.

From left to right:

Catherine Heigel
Associate General Counsel,
Duke Energy Carolinas
Charlotte, N.C.

Raiford Smith
Director,
Marketing Operations,
Marketing and Energy Efficiency
Charlotte, N.C.

Dick Stevie
Managing Director,
Customer Market Analytics
Corporate Strategy and Planning
Cincinnati, Ohio

Redefining our regulatory boundaries

Catherine Heigel advises and represents Duke Energy Carolinas and the company's other utilities on regulatory matters. She is involved in a wide variety of issues that are core to the company's future success, including rates, energy efficiency, new nuclear generation and renewable energy. Catherine has been with Duke Energy for eight years.

Raiford Smith leads a team that develops and implements new marketing projects (such as save-a-watt) and assists in developing marketing strategies and policies. His team works on solutions that have the potential to transform the industry, create new revenue streams and add customer value. Raiford has been with Duke Energy for seven years.

Dick Stevie manages a technical team that provides analytical support to organizations across the company. This includes market research, sales forecasts, energy efficiency and demand-response program analysis, load research and marketing support. Dick has been with the company for almost 27 years.

Climate Legislation Focus

The challenge we faced when we first thought about how to address climate change centered on the fact that we emit a lot of carbon dioxide (CO_2). This happens when fossil fuels are burned to produce electricity. Sure, we have nuclear and hydroelectric plants, but we also have a lot of plants that use coal, the most CO_2-intense fuel. We were concerned about how this would impact our region and our customers. Unlike many businesses, we can't simply close our operations and relocate to a lower-cost country.

We need the right federal climate legislation, and we're working to make that happen. The centerpiece has to be cap-and-trade, with provisions for a fair transition for those regions that rely on local fuels, such as coal.

We're proud of our progress in this area, but we've had help. We've been working with many stakeholders, including the U.S. Climate Action Partnership, a coalition of businesses (including our customers) and environmental groups who don't see business as the enemy. Working together, we've developed a pragmatic set of policies — a legislative blueprint for action — designed to protect the environment, keep energy prices affordable and keep the communities we serve healthy and prosperous. Learn more at www.us-cap.org.

We are also working to manage climate change risks. But to do so, the United States should set a goal to lower its greenhouse gas emissions by 80 percent by 2050. It's possible and while it won't be cheap or easy, it can still be affordable.

Electric utilities can reduce their CO_2 emissions to near zero by 2050. But to do that, we must replace nearly all coal-fueled power plants with new technologies. Because our economy is so large, we'll need to use all possible options — renewables, low-emitting coal, nuclear, natural gas and energy efficiency.

To keep the program affordable, we need to have fully developed technologies that will capture the CO_2 from coal and inject it deep underground in the same sorts of formations that have held oil and natural gas for millions of years — a process called "carbon capture and sequestration" or CCS. Some of the underlying technologies are ready now, but some need more federal support. We hope to use CCS at the integrated gasification combined cycle power plant we are building in southwestern Indiana.

As we decarbonize electricity, we can also use it to power our vehicles. Not all of this is ready right now, but it is doable and people are working to make it happen.

What about the cost? We are concerned about that as well, especially given the current state of the global economy. Capping greenhouse gas emissions must not drive up the price of electricity so much that it harms our customers and investors. That's why we've made it our business to understand the many policy options and their impact on the economy and our customers.

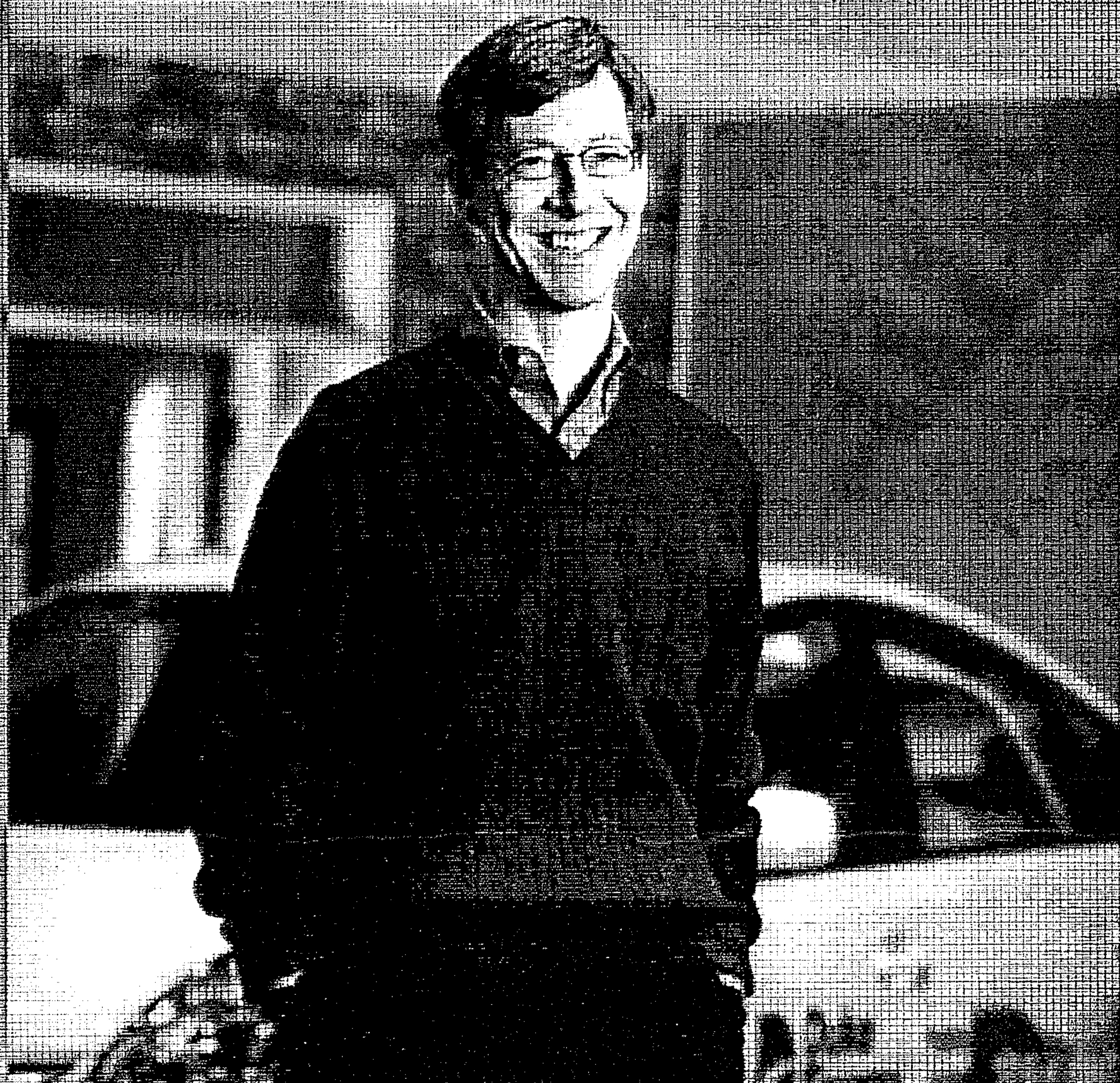
We believe that the right path is a market-based cap-and-trade approach that protects customers from rate shock by giving the value of emissions allowances to customers. The local distribution company, perhaps better known as your local power company, is the most effective and efficient vehicle for delivering this allowance value to customers. Done right, climate change legislation won't harm our economy. Done wrong, such as a cap-and-trade system with a 100 percent auction of emissions allowances, customers will unnecessarily see dramatic increases in their bills.

Putting a price on carbon will increase energy prices, and we are concerned about the impact that will have on the average household and small business, not to mention our larger customers. Our focus is on how to minimize the increases and make them happen slowly, over time. We are also advancing plans, such as our save-a-watt program (see page 22) to help our customers use less energy so as prices increase, the hit on their bank accounts will be less.

Kevin Leahy
Managing Director, Climate Policy
Cincinnati, Ohio

Redefining climate change legislation

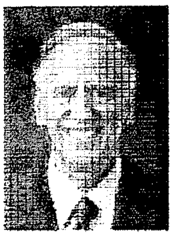
Kevin Leahy serves as an internal environmental economist, analyzing the economic impact of proposed and existing environmental policies on Duke Energy and its customers. He helps create the company's positions on and develops strategies to help address these policies, especially federal climate change legislation. He also serves as a "bridge" between the company and its diverse stakeholder groups on policy issues. Kevin has been with the company for [illegible] years.



Board of Directors

William Barnet III
Chairman, President and CEO, The Barnet Co. Inc. and Barnet Development Corp.
Chair, Finance and Risk Management Committee; Member, Nuclear Oversight Committee

Director of Duke Energy or its predecessor companies since 2005. Barnet has been the mayor of Spartanburg, S.C., since 2002. He serves on the board of Bank of America and is a trustee of The Duke Endowment. He is a former chairman of the Palmetto Business Forum and the board of trustees of Converse College.



G. Alex Bernhardt Sr.
Chairman and CEO, Bernhardt Furniture Co.; Member, Audit and Nuclear Oversight Committees

Director of Duke Energy or its predecessor companies since 1991. Bernhardt joined the family business in 1965 and became chairman and CEO in 1996. He serves on the boards of directors of Communities In Schools and the North Carolina Nature Conservancy. He is director emeritus and past president of the American Furniture Manufacturers Association, and past president of the International Home Furnishings Marketing Association.

Michael G. Browning
President and Chairman of the Board, Browning Investments Inc.
Chair, Audit Committee
Member, Corporate Governance and Finance and Risk Management Committees

Director of Duke Energy or its predecessor companies since 1990. Browning is vice chairman of the Indianapolis Convention and Visitors Association. He is a board member of the Indianapolis Museum of Art and serves on the Graduate School Advisory Council of the University of Notre Dame. Browning is a member of the Indiana Public Officers Compensation Committee.

Daniel R. DiMicco
Chairman, President and CEO, Nucor Corp.; Member, Audit, Compensation and Corporate Governance Committees

Director of Duke Energy or its predecessor companies since 2007. DiMicco joined Nucor Corp. in 1982 and held a number of senior positions before being named chairman in 2006. He is a former chair of the American Iron and Steel Institute. DiMicco was named the Charlotte Business Journal's 2008 Businessperson of the Year.

Ann Maynard Gray
Former President, Diversified Publishing Group of ABC Inc.
Lead Director; Chair, Corporate Governance Committee; Member, Compensation and Finance and Risk Management Committees

Director of Duke Energy or its predecessor companies since 1994. Gray has held a number of senior positions with American Broadcasting Companies, including senior vice president of finance, treasurer and vice president of planning. She serves on the boards of the Phoenix Companies, Inc. and Elan Corporation, plc. She is a past member of the board of trustees of J.P. Morgan Funds.

James H. Hance Jr.
Retired Vice Chairman, Chief Financial Officer and Board Member, Bank of America Corp. Chair, Compensation Committee; Member, Finance and Risk Management Committee

Director of Duke Energy or its predecessor companies since 2005. A certified public accountant, Hance served Bank of America and its predecessor for 18 years and spent 17 years with Price Waterhouse. He serves on the boards of Sprint Nextel Corp., Cousins Properties Inc. and Rayonier Inc. He is trustee of Washington University and Johnson & Wales University.

James T. Rhodes
Retired Chairman, President and CEO, Institute of Nuclear Power Operations (INPO). Chair, Nuclear Oversight Committee; Member, Audit Committee

Director of Duke Energy or its predecessor companies since 2001. Rhodes serves on the Electric Power Research Institute's advisory council and is a former board member of INPO, the Nuclear Energy Institute, Edison Electric Institute and the Southeastern Electric Exchange. He is a former president and CEO of Virginia Power and a past board member of Dominion Resources.

James E. Rogers
Chairman, President and CEO, Duke Energy

Rogers became chairman, president and CEO of Duke Energy in 2007, having served as chairman and CEO of Cinergy since 1994 and PSI Energy since 1988. He is chairman of the Institute for Electric Efficiency and the Edison Foundation, and serves as co-chair of the National Action Plan for Energy Efficiency and the Alliance to Save Energy. He is a director of Cigna Corp. and Applied Materials Inc. Rogers serves on the boards and Executive Committees of the Nuclear Energy Institute and the World Business Council for Sustainable Development. He is a board member of the Institute of Nuclear Power Operations, the Business Roundtable and the Nicholas Institute for Environmental Policy Solutions. He is also a member of the Honorary Committee of the Joint U.S.-China Cooperation on Clean Energy.

Philip R. Sharp
President, Resources for the Future; Member, Audit and Nuclear Oversight Committees

Director of Duke Energy since 2007, having served on a predecessor company's board from 1995 to 2006. Sharp serves on the board of directors of the Energy Foundation and is a former member of the Indiana delegation to the U.S. House of Representatives. He served as Congressional chair of the National Commission on Energy Policy and was a member of the House Energy and Commerce Committee.

Dudley S. Taft
President and CEO, Taft Broadcasting Co.; Member, Compensation and Finance and Risk Management Committees

Director of Duke Energy or its predecessor companies since 1994. Taft serves on the boards of the Unifi Mutual Holding Co. and Fifth Third Bancorp. He is chairman of the Cincinnati Association for the Arts and a trustee of Boys and Girls Club of Greater Cincinnati and the Cincinnati Institute of Fine Arts.

Executive Management

Roberta B. Bowman
Senior Vice President and Chief Sustainability Officer

Bowman is responsible for the company's strategy to balance environmental, economic and social issues and opportunities. She has more than 30 years of experience in energy, including roles in public policy issues management and stakeholder relations. Bowman also serves on a number of industry, community and business boards, including Women Corporate Directors.

Brett C. Carter
President, Duke Energy Carolinas

Carter leads Duke Energy's utility business in North Carolina and South Carolina including its legislative and regulatory strategy, economic development and community affairs. Duke Energy Carolinas serves approximately 2.4 million customers. Previously, Carter served as senior vice president of customer service and business development for Duke Energy. In 2008, he was appointed by the governor to the North Carolina State Ports Authority Board. He also serves on several community boards including Crisis Assistance Ministry.

Lynn J. Good
Group Executive and President, Commercial Businesses

Good is responsible for Midwest nonregulated generation, Duke Energy International, the telecommunications businesses, and all corporate development and merger and acquisition activities. She also leads Duke Energy Generation Services, the business that develops, owns and operates fossil fuel and renewable generation assets. Previously, Good served as senior vice president and treasurer for Duke Energy. Prior to that, she was Cinergy's chief financial officer.

David L. Hauser
Group Executive and Chief Financial Officer

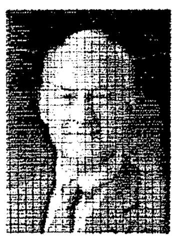
Hauser became Duke Energy's chief financial officer in 2004. Since joining the company in 1973, positions he has held include controller, vice president of procurement services and materials, senior vice president of global asset development and senior vice president and treasurer. Hauser has chaired the Edison Electric Institute's FERC Accounting Liaison Group and General Accounting Committee.

Dhiaa M. Jamil
Group Executive and Chief Nuclear Officer

Jamil is responsible for the safe and efficient operation of the company's nuclear generating stations. He has more than 28 years of experience in the energy industry and previously served as senior vice president of nuclear support for the company. Jamil is a member of the INPO Executive Advisory Group and the Nuclear Energy Institute's Strategic Initiative Advisory Committee.

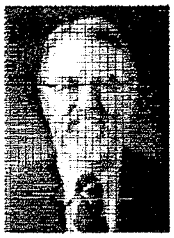
Julie S. Janson
President, Duke Energy Ohio and Duke Energy Kentucky

Janson leads Duke Energy's Ohio and Kentucky utility businesses, including legislative and regulatory strategy, economic development and community affairs. Duke Energy serves approximately 825,000 customers in Ohio and Kentucky. Previously, Janson served as senior vice president of ethics and compliance, and corporate secretary for Duke Energy. Prior to that, she served as corporate secretary and chief compliance officer for Cinergy.



Marc E. Manly
Group Executive, Chief Legal Officer and Corporate Secretary

Manly leads Duke Energy's office of general counsel, which includes internal audit, ethics and compliance, legal and human resources. He served as Cinergy's executive vice president and chief legal officer since 2002. Before joining Cinergy, Manly served as managing director for law and governmental affairs, general counsel and corporate secretary for NewPower Holdings Inc.



David W. Mohler
Vice President and Chief Technology Officer

Mohler is responsible for the development and application of technologies in support of Duke Energy's strategic objectives. Previously, he served as vice president of strategic planning for Duke Energy, a position he also held at Cinergy. Mohler serves on the Electric Power Research Institute's Research Advisory Committee and the boards of GridPoint and Advanced Energy Corp.

Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

Rolfe leads several of Duke Energy's corporate functions, including supply chain, information technology, operations services and other administrative activities. He previously served as group executive and chief human resources officer for Duke Energy. Rolfe joined Duke Power in 1972 as an engineering assistant and eventually worked on most of the utility's fossil, hydro and nuclear projects.

Ellen T. Ruff
President, Office of Nuclear Development

Ruff is responsible for furthering the development of new nuclear generation in the Carolinas, including advancing Duke Energy's plans for the proposed Lee Nuclear Station. She was formerly president of Duke Energy Carolinas. Ruff serves on the boards of directors of the North Carolina Chamber and the South Carolina Manufacturers Alliance, and is a member of the Palmetto Business Forum.

Jim L. Stanley
President, Duke Energy Indiana

Stanley leads Duke Energy's Indiana utility business, including its legislative and regulatory strategy, economic development and community affairs. Duke Energy Indiana serves approximately 775,000 customers. Previously, Stanley served as vice president of field operations for Duke Energy's Midwest service area. He serves on the boards of directors of the Indiana Energy Association and the Central Indiana Corporate Partnership.

R. Sean Trauschke
Senior Vice President, Investor Relations and Financial Planning

Trauschke is responsible for monitoring trends in investment markets and for maintaining key relationships with investors, financial analysts and financial institutions, as well as oversight of corporate financial planning and analysis. He joined the company in 1989. Prior to his current position, Trauschke served as Duke Energy's chief risk officer and chief credit officer.

B. Keith Trent
Group Executive and Chief Strategy, Policy and Regulatory Officer

Trent is responsible for strategy, state and federal policy and government affairs, technology initiatives, corporate communications, community affairs, and environment, health and safety policy. His team includes the regulated utility company presidents' organizations, which have responsibility for regulatory and legislative activities in five states. Trent has more than 18 years of experience as an accomplished legal counselor. He serves on the board of Bright Automotive Inc. and is co-chair of The Keystone Energy Board.

James L. Turner
Group Executive, President and
Chief Operating Officer
U.S. Franchised Electric and Gas

Turner has profit and loss responsibility for Duke Energy's largest business segment, which serves approximately 4 million customers. He oversees the company's fossil-hydro generation, power delivery, gas distribution, customer service, sales and marketing, wholesale business, new generation projects, smart grid implementation, and the environment, health and safety organization. Turner serves on the board of EnerNOC Inc., a firm specializing in demand management.

Non-GAAP Financial Measures

2008 Adjusted Diluted Earnings Per Share (EPS)
Duke Energy's 2008 Summary Annual Report references 2008 adjusted diluted EPS of $1.21. Adjusted diluted EPS is a non-GAAP (generally accepted accounting principles) financial measure as it represents diluted EPS from continuing operations, adjusted for the per-share impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. Mark-to-market adjustments reflect the mark-to-market impact of derivative contracts, which is recognized in GAAP earnings immediately as such derivative contracts do not qualify for hedge accounting or regulatory accounting, used in Duke Energy's hedging of a portion of the economic value of certain of its generation assets in the Commercial Power segment. The economic value of the generation assets is subject to fluctuations in fair value due to market price volatility of the input and output commodities (e.g., coal, power) and, as such, the economic hedging involves both purchases and sales of those input and output commodities related to the generation assets. Because the operations of the generation assets are accounted for under the accrual method, management believes that excluding the impact of mark-to-market changes of the economic hedge contracts from adjusted earnings until settlement better matches the financial impacts of the hedge contract with the portion of the economic value of the underlying hedged asset. The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS from continuing operations, which includes the impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. The following is a reconciliation of reported diluted EPS from continuing operations to adjusted diluted EPS for 2008:

	2008
Diluted EPS from continuing operations, as reported	$ 1.01
Diluted EPS from discontinued operations, as reported	0.01
Diluted EPS from extraordinary items, as reported	0.05
Diluted EPS, as reported	1.07
Adjustments to reported EPS:	
Diluted EPS from discontinued operations	(0.01)
Diluted EPS from extraordinary items	(0.05)
Diluted EPS impact of special items and mark-to-market in Commercial Power (see below)	0.20
Diluted EPS, adjusted	**$ 1.21**

The following is the detail of the $(0.20) in special items and mark-to-market in Commercial Power impacting adjusted diluted EPS for 2008:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2008 Diluted EPS Impact
Costs to achieve the Cinergy merger	$ (44)	$17	$(0.02)
Crescent project impairments	[illegible]	[illegible]	(0.10)
Emission allowances impairment	[illegible]	[illegible]	(0.04)
Mark-to-market impact of economic hedges	[illegible]	[illegible]	(0.04)
Total Adjusted Diluted EPS impact			**$(0.20)**

2008 Employee Incentive Target Measure
Duke Energy's 2008 Summary Annual Report references the company's 2008 employee EPS incentive target. The EPS measure used for employee incentive bonuses is primarily based on adjusted diluted EPS. The materials also reference the forecasted range of growth in adjusted diluted EPS through 2013 on a compound annual growth rate (CAGR) basis. Adjusted diluted EPS is a non-GAAP financial measure, as it represents diluted EPS from continuing operations, adjusted for the per-share impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. Mark-to-market adjustments reflect the mark-to-market impact of derivative contracts, which is recognized in GAAP earnings immediately as such derivative contracts do not qualify for hedge accounting or regulatory accounting, used in Duke Energy's hedging of a portion of the economic value of certain of its generation assets in the Commercial Power segment. The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS from continuing operations, which includes the impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project special items or mark-to-market adjustments for future periods.

Forecasted 2009 Adjusted Segment EBIT and 2008 Adjusted Total Segment EBIT
Duke Energy's 2008 Summary Annual Report includes a discussion of forecasted 2009 adjusted EBIT for each of Duke Energy's reportable segments as a percentage of forecasted 2009 adjusted total segment EBIT and a reference to the company's total 2008 adjusted segment EBIT. Forecasted 2009 adjusted segment and total segment EBIT amounts are non-GAAP financial measures, as they represent reported segment EBIT adjusted for the impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. Mark-to-market adjustments reflect the mark-to-market impact of derivative contracts, which is recognized in GAAP earnings immediately, as such derivative contracts do not qualify for hedge accounting or regulatory accounting used in Duke Energy's hedging of a portion of the economic value of certain of its generation assets in the Commercial Power segment. The most directly comparable GAAP measures for adjusted segment EBIT and total segment EBIT are reported segment EBIT and total segment EBIT, which represent segment results from continuing operations, including any special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Due to the forward-looking nature of this non-GAAP financial measure for 2009, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project special items or mark-to-market adjustments for future periods.

The following is a reconciliation of 2008 adjusted segment EBIT to reported segment EBIT:

	Adjusted EBIT	Special Items – Emission Allowances Impairment	Economic Hedges (Mark-to-Market)	Reported EBIT
U.S. Franchised Electric and Gas	$ 2,398	$ —	$ —	$ 2,398
Commercial Power	421	(82)	(75)	264
International Energy	411	—	—	411
Total segment EBIT	**$ 3,230**	**$ (82)**	**$ (75)**	**$ 3,073**

Forward-Looking Statement

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target" and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to: state, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements; state, federal and foreign legislative and regulatory initiatives and rulings that affect cost and investment recovery or have an impact on rate structures; costs and effects of legal and administrative proceedings, settlements, investigations and claims; industrial, commercial and residential growth in Duke Energy's service territories; additional competition in electric markets and continued industry consolidation; political and regulatory uncertainty in other countries in which Duke Energy conducts business; the influence of weather and other natural phenomena on Duke Energy's operations, including the economic, operational and other effects of storms, hurricanes, droughts and tornados; the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates; unscheduled generation outages, unusual maintenance or repairs and electric transmission system constraints; the performance of electric generation and of projects undertaken by Duke Energy's nonregulated businesses; the results of financing efforts, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions; declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans; the level of credit worthiness of counterparties to Duke Energy's transactions; employee workforce factors, including the potential inability to attract and retain key personnel; growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power and other projects; construction and development risks associated with the completion of Duke Energy's capital investment projects in existing and new generation facilities, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards, as well as the ability to recover costs from ratepayers in a timely manner; the effect of accounting pronouncements issued periodically by accounting standard-setting bodies; and the ability to successfully complete merger, acquisition or divestiture plans.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Investor Information

Annual Meeting

The 2009 Annual Meeting of Duke Energy Shareholders will be:

Date: Thursday, May 7, 2009
Time: 10 a.m.
Place: O.J. Miller Auditorium
Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services

Shareholders may call 800-488-3853 or 704-382-3853 with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Additionally, registered users of DUK-Online, our online account management service, may access their accounts through the Internet.

Send written requests to:
Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005

For electronic correspondence, visit www.duke-energy.com/contactIR.

Stock Exchange Listing

Duke Energy's common stock is listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Addresses

Corporate home page:
www.duke-energy.com
Investor Relations:
www.duke-energy.com/investors

InvestorDirect Choice Plan

The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available.

The plan also provides for full reinvestment, direct deposit or cash payment of dividends. Additionally, participants may register for DUK-Online, our online account management service.

Financial Publications

Duke Energy's summary annual report, SEC Form 10-K and related financial publications can be found on our Web site at www.duke-energy.com/investors. Printed copies are also available free of charge upon request.

Duplicate Mailings

If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar

Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common stock.

Dividend Payment

Duke Energy has paid quarterly cash dividends on its common stock for 82 consecutive years. For the rest of 2009, dividends on common stock are expected to be paid, subject to declaration by the Board of Directors, on June 16, Sept. 16 and Dec. 16, 2009.

Bond Trustee

If you have questions regarding your bond account, call 800-275-2048, or write to:
The Bank of New York Mellon
Global Trust Services
101 Barclay Street
New York, NY 10286

Send Us Feedback

We welcome your opinion on this summary annual report. Please visit www.duke-energy.com/investors, where you can view and provide feedback on both the print and online versions of this report. Or contact Investor Relations directly.

Duke Energy is an equal opportunity employer. This report is published solely to inform shareholders and is not to be considered an offer, or the solicitation of an offer, to buy or sell securities.

Mixed Sources

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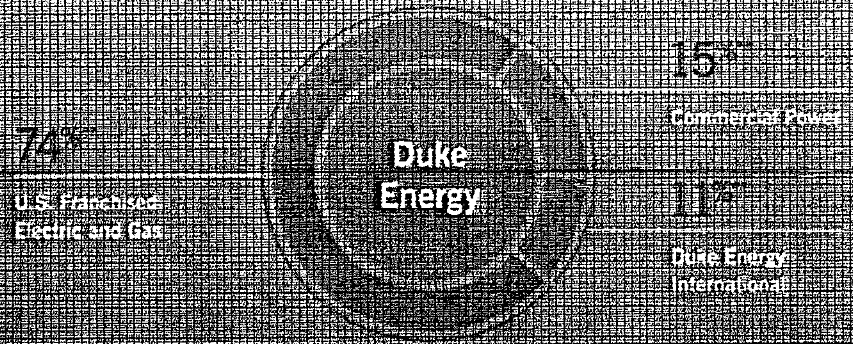
Duke Energy at a Glance

2009 Adjusted Segment EBIT*



U.S. Franchised Electric and Gas

U.S. Franchised Electric and Gas (USFE&G) consists of Duke Energy's regulated generation, electric and gas transmission and distribution systems. Its generation portfolio is a mix of fuel sources — coal, oil/natural gas, nuclear and hydroelectric. USFE&G is Duke Energy's largest business segment and primary source of earnings.

Electric Operations

- Owns approximately 27,400 megawatts of generating capacity
- Supplies electric service to approximately 4 million customers
- Serves territories in five states — North Carolina, South Carolina, Ohio, Indiana and Kentucky — that total about 48,300 square miles with an estimated population of 11 million
- Operates 150,900 miles of distribution lines and a 20,200-mile transmission system

Gas Operations

- Provides regulated transmission and distribution service to approximately 500,000 customers over a 3,000-square-mile service territory in Ohio and Kentucky

Commercial Power

Commercial Power owns, operates and manages power plants, primarily in the Midwest. Commercial Power also includes Duke Energy Generation Services (DEGS), which develops, owns and operates generation sources (including wind assets) that serve large energy consumers, municipalities, utilities and industrial facilities.

- Owns and operates a balanced generation portfolio of approximately 7,550 megawatts (excluding wind portfolio)
- Approximately 4,000 megawatts are dedicated to serve regulated customers in Ohio
- DEGS currently has approximately 570 megawatts of wind energy in operation and over 5,000 megawatts of wind energy projects in the potential development pipeline

Duke Energy International

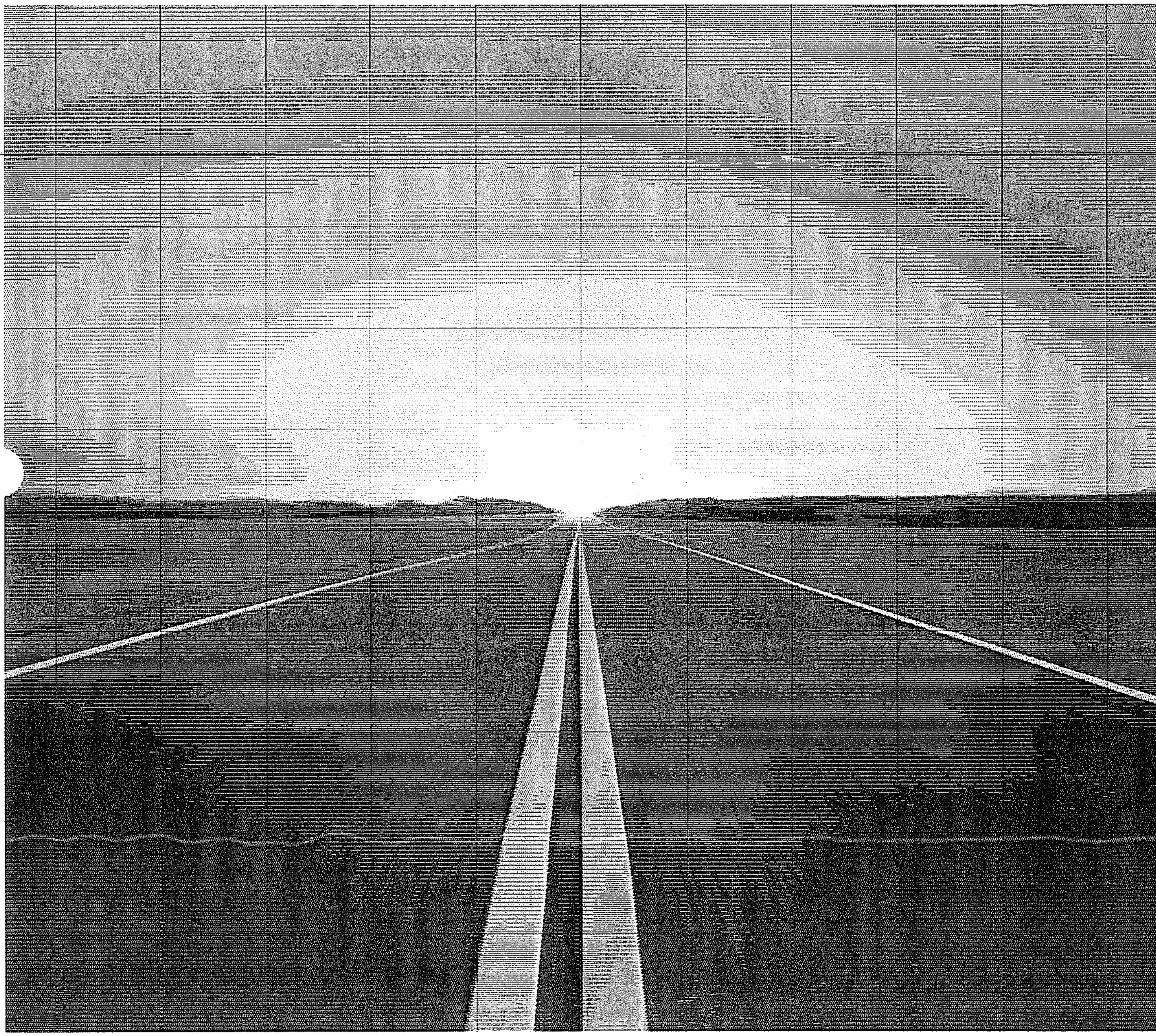
Duke Energy International (DEI) operates and manages power generation facilities located in six Central and South American countries of Argentina, Brazil, Ecuador, El Salvador, Guatemala and Peru. DEI also owns equity investments in Saudi Arabia and Greece.

- Owns, operates or has substantial interests in approximately 4,000 net megawatts of generation facilities
- About 75 percent of DEI's generating capacity is hydroelectric. For 2009, approximately 90 percent of sales [illegible]

[illegible]

Progress Energy

ANNUAL REPORT 06



THE ROAD AHEAD

SHIFTING INTO HIGH GEAR

"IT'S BEEN A TIME OF **TRANSFORMATION** AT PROGRESS ENERGY, OF FOCUS ON **WHAT WE DO BEST.**

AS A RESULT, WE'VE NEVER BEEN MORE CLEAR ON **WHO WE ARE** – AND **WHERE WE'RE GOING.**"

— **Robert B. McGehee**
Chairman and CEO

In 2000, when Carolina Power & Light and Florida Progress joined to form Progress Energy, we were a very different company than we are today.

Now, just six years later, we are on the road to becoming the country's largest utility focused solely on the regulated electric utility business. We have a strong balance sheet and a clear, achievable strategy for growth.

Today, we are at our best because we are focused on what we do best: the electric utility business. We have followed through on our commitment to divest noncore holdings and reduce debt. At the same time, we have made significant investments in our regulated utilities, Progress Energy Carolinas and Progress Energy Florida, bringing both to a level of industry leadership recognized in 2006 by the Edison Electric Institute.

And now we are ready to drive our company forward successfully for our communities, our shareholders and our employees.

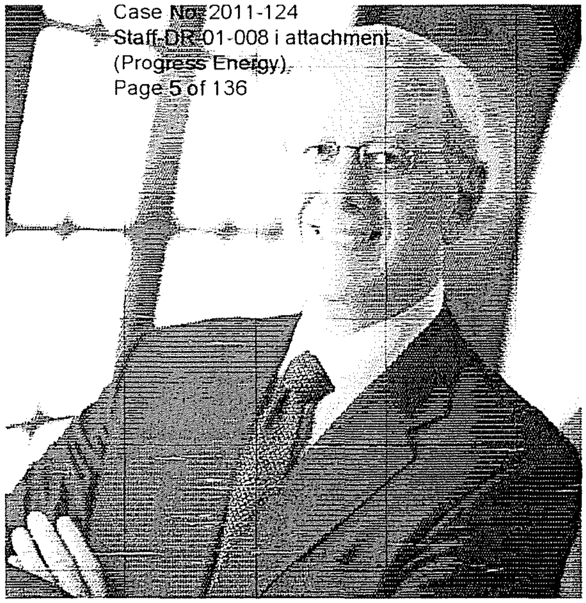
With our strong operational record, growing customer base, constructive regulatory environments and tremendous opportunities for growth, we see a bright future for Progress Energy. And we want to share with you our enthusiasm for *The Road Ahead*.

TABLE OF CONTENTS

Years ended December 31 (in millions, except per share data)	**2006**	2005*	2004*
Financial Data			
Operating revenues	**$9,570**	$9,168	$8,053
Net income	**571**	697	759
Income from continuing operations	**514**	721	673
Ongoing earnings per common share**	**2.58**	3.31	2.86
Reported GAAP earnings per common share	**2.28**	2.82	3.13
Average common shares outstanding	**250**	247	242
Common Stock Data			
Return on average common stock equity (percent)	**7.05**	8.91	9.99
Book value per common share	**$32.71**	$32.35	$31.39
Market value per common share (closing)	**$49.08**	$43.92	$45.24

**Financial data has been restated for discontinued operations.*

***See page 130 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*



Dear Shareholders:

Progress Energy had a very successful year in 2006 and has entered 2007 with a healthy balance sheet and a clear strategic focus. We are concentrating on our two strong electric utilities and the robust growth in the Carolinas and Florida. I'm enthusiastic about the road ahead.

In 2006 we created substantial positive momentum in both operational and financial performance and laid the strategic groundwork for the next 15 to 20 years.

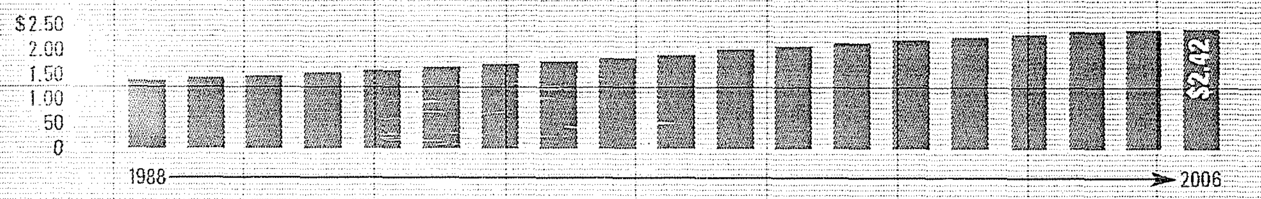
The operational excellence achieved by our employees earned Progress Energy our industry's highest honor: the Edison Award. This national recognition came on the heels of our becoming the first utility in the nation to win the J.D. Power Founder's Award, which recognizes commitment to customer satisfaction, in late 2005. These back-to-back awards reflect the priority we place on excelling in the fundamentals of the utility business. It's the foundation for our success.

Progress Energy also made significant progress on the financial front in 2006. We met our ongoing earnings-per-share target, increased our dividend for the 19th consecutive year and earned a total shareholder return of 18.1 percent for the year. We expect to produce ongoing earnings growth in 2007 and 2008 that is substantially greater than the 3 percent to 5 percent that we had previously targeted from our core businesses.

Selling non-utility businesses enabled us to reduce holding company debt by $1.7 billion in 2006 and meet our debt-reduction goal a year ahead of schedule. We lowered our ratio of debt to total capitalization to 52 percent, strengthening credit quality.

A COMPANY TRANSFORMED AND FOCUSED Progress Energy now has the strongest balance sheet and clearest strategic focus we've had in years and it's centered on what we know and do best: the regulated

19 YEARS OF DIVIDEND GROWTH



electric utility business. It's our singular focus based on a deliberate corporate transformation.

The road to this point hasn't been easy. Although the 2000 merger that created Progress Energy was a good strategic combination, it left us with significant debt that took longer than expected to pay down. It also produced a complex corporate structure with more than a dozen operating subsidiaries, including volatile businesses such as synthetic fuels, natural gas production and non-utility power generation. This divided our attention and exposed our company to more risk than we like.

As of early 2007, however, we've nearly finished exiting the nonregulated businesses, and we expect to complete these divestitures in 2008. This will make us the largest U.S. utility solely focused on the regulated electric utility business.

A clear focus is especially important now because the world and the electric power industry are dealing with turbulent times. We face fuel price volatility and complex environmental issues such as global climate change. On the positive side, there's the opportunity to reap the benefits of today's greater potential for energy efficiency and renewable energy as well as for new advanced-nuclear and clean-coal technologies.

LONG VIEW; BALANCED SOLUTION. In our strategic planning in 2006, we involved more people and looked farther ahead than ever before – considering not just the next three to 10 years but also the next 15 to 20 years. We examined everything from fuel price trends to emerging technologies and environmental policies. We also analyzed how best to manage the very large capital requirements for new generation and transmission infrastructure as well as for additional emission-control equipment.

As a result of this planning, which we continually update as conditions change, we are implementing a balanced approach to addressing the increasing energy demand fueled by growth in the Carolinas and Florida.

The three main elements of this balanced solution are: increasing energy efficiency and supporting the development of renewable energy sources for the future; modernizing existing plants to produce energy more cleanly and efficiently using state-of-the-art technology; and investing in new generating plants. The results of this approach will be a highly reliable energy supply, more stable electricity prices, a cleaner environment and less dependence on imported energy.

We are moving forward on all three fronts. For example, we have announced more aggressive energy-efficiency initiatives and alternative energy projects, including plants fueled by landfill gas, animal waste and the bamboo-like e-grass™ as well as solar and hydrogen applications.

As for existing plants, we announced major initiatives last year to increase the power output of our Crystal River Nuclear Plant and to convert the oil-fired Bartow Plant to natural gas. (The Bartow project will double the plant's output while reducing air emissions in the densely populated Tampa Bay region.) Also in 2006, our Brunswick Nuclear Plant received a 20-year extension on its federal operating licenses and earned the nuclear industry's Best of the Best Award for its capacity-upgrade project.

We're also taking steps to prepare for adding new generating facilities. In 2006 we announced two sites for potential nuclear expansion: one site in Levy County, Fla., and the other in Wake County, N.C. We are hard at work on the extensive license applications for these two nuclear projects to keep these promising options open, but we're not at the point where we need to make a final decision to pursue either project.

We recognize that no single technology or initiative will be sufficient to meet the growing energy demands of our customers and the region we serve while also fulfilling our environmental commitments. That's why we're blending the strengths of multiple approaches and retaining the flexibility to adjust our plans to new developments.

THANKS WHERE THANKS IS DUE. As important as plans, technologies and service territories are in our business, it's the people of Progress Energy and the way they work together that give our company a performance edge.

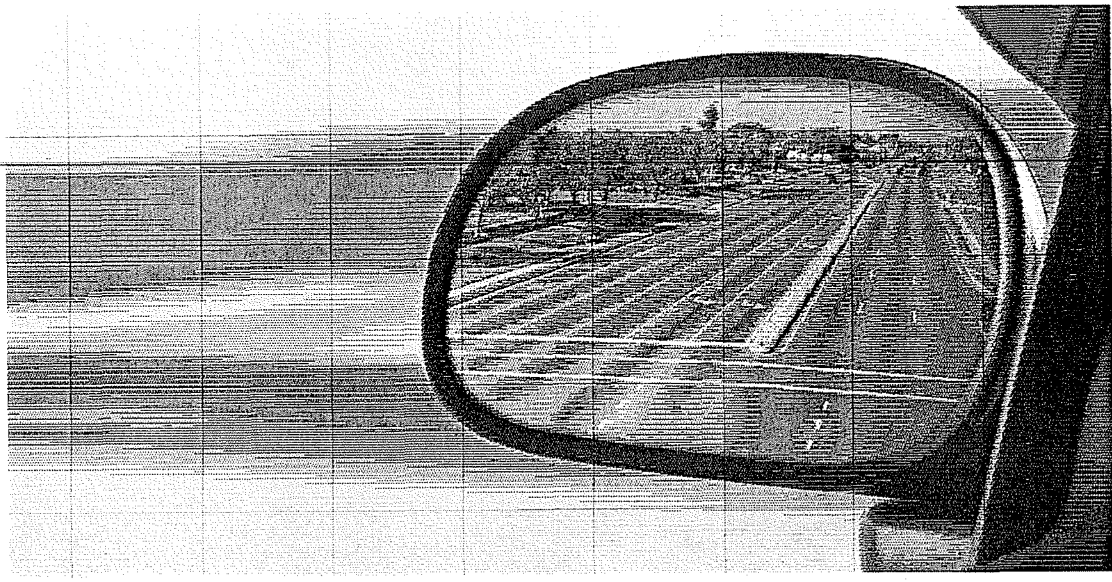
I am immensely grateful for the superb way our more than 10,000 employees meet every challenge, whether quickly responding to damaging storms or generously helping with community needs. (Our 2006 employee charitable-giving campaign exceeded its $1.8 million goal by 12 percent.)

The people here, including an experienced leadership team, make this a company I'm honored to lead and serve. Our investors and customers have good reason to feel confident about the road ahead.

Robert B. McGehee

Robert B. McGehee
Chairman and Chief Executive Officer

THE ROAD BEHIND
Where We've Been



The past several years have been a time of transformation for Progress Energy, of meeting our commitments and narrowing our focus as we prepare to accelerate forward.

TRUE TO OUR WORD. At Progress Energy, we have a consistent record of meeting our commitments to our customers, shareholders and employees.

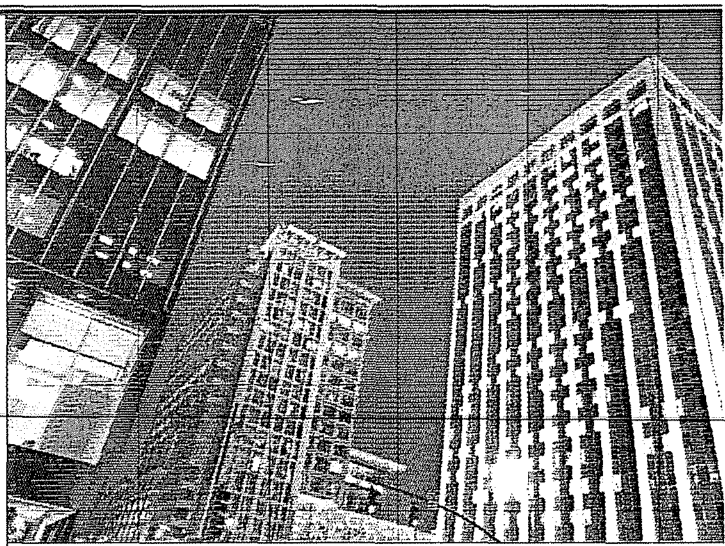
Following the merger in 2000, we were faced with significant debt as well as a complex, diversified corporate structure, all of which exposed us to more volatility and risk than desirable. To mitigate these factors, we made a commitment to reduce debt, strengthen our balance sheet in preparation for future growth and focus on our core electric utility business – all of which we have now achieved, including a $1.7 billion reduction in holding company debt.

We have divested most of our noncore assets. Through rigorous cost management, we have significantly slowed the growth of

our annual nonfuel operating expenses. And we have successfully resolved critical issues such as the IRS audit of four of our synthetic fuels facilities.

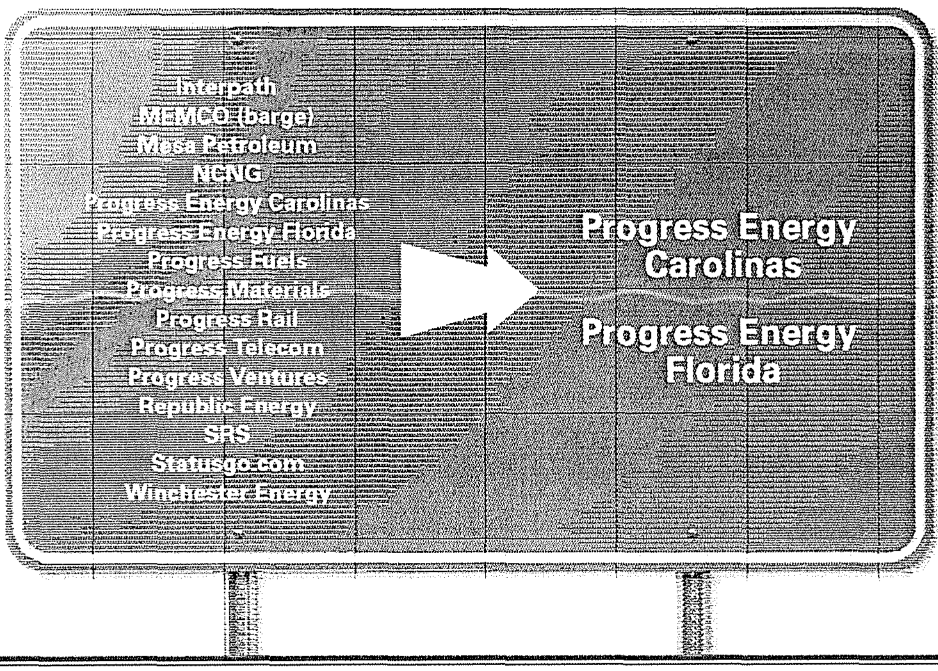
INVESTING IN OUR UTILITIES. As part of our effort to focus on our core utilities, we launched an ambitious plan to raise customer satisfaction, reliability and safety standards at Progress Energy Florida. This three-year, $100 million Commitment to Excellence program accomplished its goals, bringing Progress Energy Florida to a new level of industry leadership. We've continued to pursue constant improvements and have achieved a 26 percent increase in reliability since 2000.

Efforts like these at both our utilities have greatly improved customer satisfaction, as evidenced in 2005 when we became the first utility ever to win the prestigious J.D. Power Founder's Award for customer service.



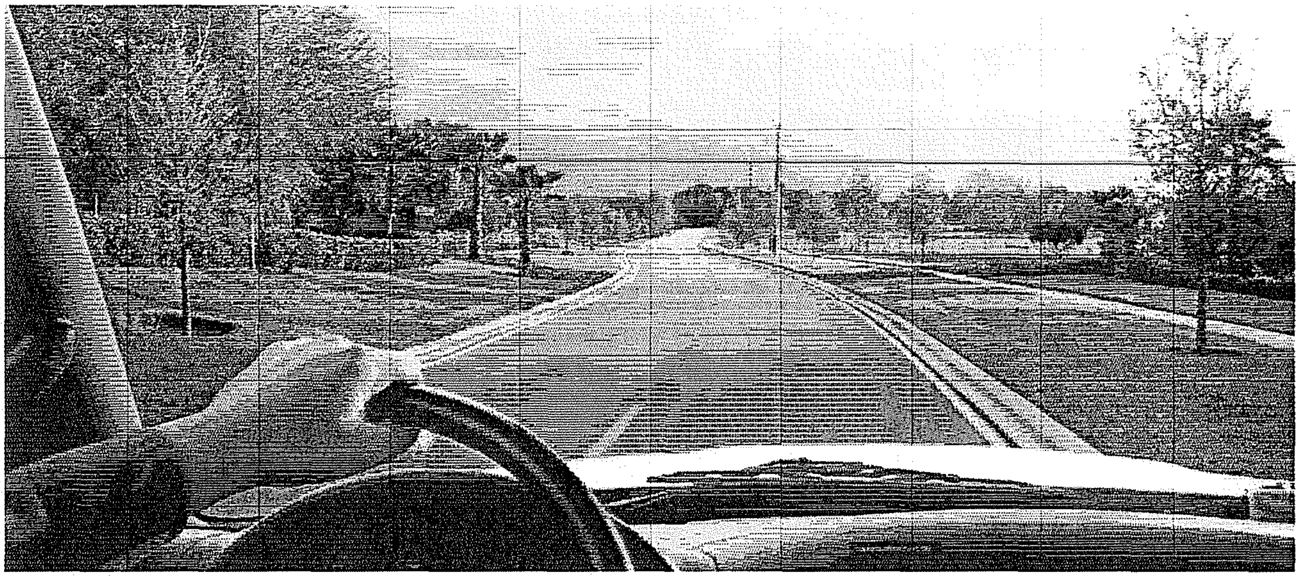
DRIVEN TO SUCCEED. With our restored balance sheet, improved focus and reduced risk, Progress Energy is poised to take advantage of the opportunities in our growing communities to fuel long-range earnings growth and shareholder returns.

Now, more than ever, Progress Energy is positioned to be a buy-and-hold stock offering superior, lower-risk returns.



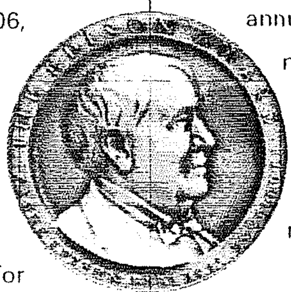
NARROWING OUR FOCUS. *Over the last six years, we have divested most of our noncore assets, allowing us to focus on our core regulated utilities. This enables us to reduce risk, play to our strengths, and build a platform for strong, sustainable growth into the future.*

THE ROAD HERE
Where We Are Now



Excelling at the fundamentals is what sets Progress Energy apart. From operations and customer service to our relationships in the community, we set the highest standards for ourselves and always strive to exceed them.

PROVEN INDUSTRY LEADER. In 2006, Progress Energy was awarded the industry's highest honor, the Edison Award, in recognition of our innovation and industry leadership. Also in 2006 – for the second year in a row – PA Consulting Group named us the ServiceOne winner for exceptional customer service. This recognition shows that the pursuit of ever-higher standards is deeply ingrained in our culture.



Again this year, our nuclear and fossil-fueled plants were ranked among the industry's best in production, safety and cost efficiency. And the company completed a breakthrough mobile meter reading project that is expected to save $21 million annually in operating costs while increasing meter accuracy and customer convenience.

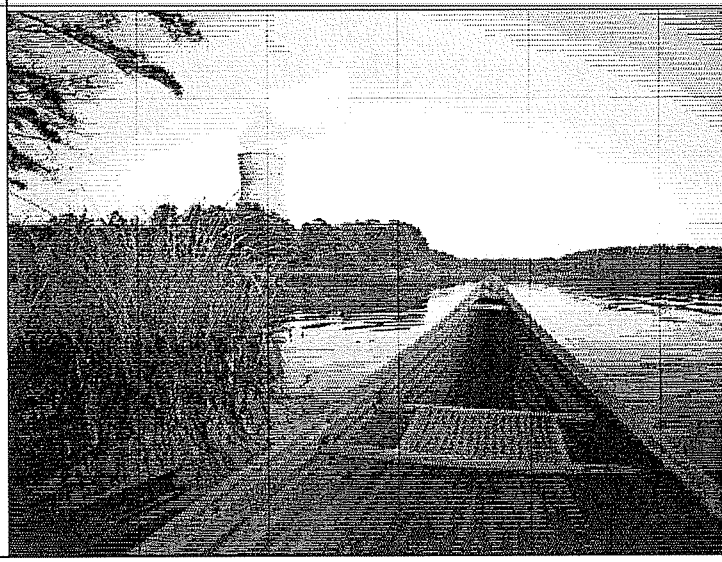
In short, we see every aspect of our operations as an opportunity to exceed our previous standards and provide a new level of satisfaction to our customers.

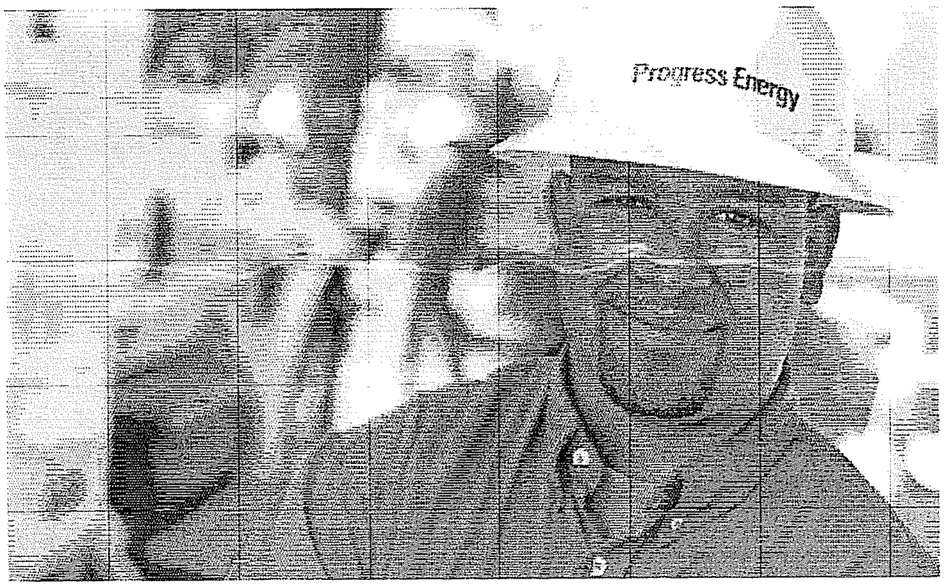
LEADER IN ENVIRONMENTAL STEWARDSHIP. At Progress Energy, we are preparing today for tomorrow's additional environmental regulations, implementing state-of-the-art upgrades that will make coal-fired plants such as our Asheville facility among the cleanest in the country. And, once again in 2006, the company was named to the Dow Jones Sustainability Index as an industry leader for our business approach to economic, environmental and social issues.

STRONG PARTNERSHIPS WITH OUR COMMUNITIES. A regulated utility cannot thrive without strong, positive relationships with its communities and the people who live there.

Progress Energy has a long history of supporting and enriching its service areas. In 2006, Progress Energy and the Progress Energy Foundation donated more than $12 million to community initiatives. The company also actively partnered with local leaders in our communities to recruit new businesses, which created nearly 7,000 new jobs and pumped more than $1.3 billion in capital investment into the local economy.

A FOUNDATION OF TRUST. At Progress Energy, we have a reputation for meeting our customers' needs reliably and efficiently – and for working with public officials and regulators cooperatively and constructively. Our actions and our reputation together form a foundation upon which we are building for the future.

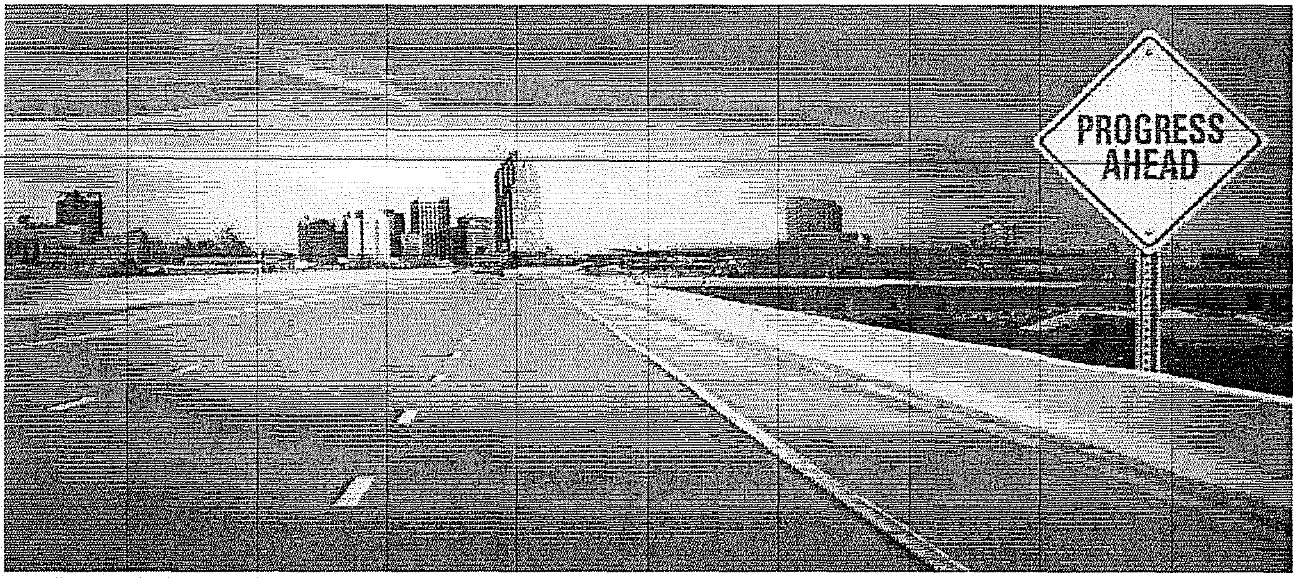




Martin Rivera, lineman

COMMITTED WORKFORCE. *The Progress Energy workforce, more than 10,000 strong, is among the safest, most productive and well trained in the industry. That's one reason in 2006 BusinessWeek named Progress Energy one of the 50 best places in the country to launch a career.*

THE ROAD AHEAD
Where We Are Going



Our customer base is growing rapidly. And so is energy demand. At Progress Energy, we have a balanced approach for meeting that demand so we can grow with our service area, deliver reliable, cost-efficient power and bring long-term results to our shareholders.

GROWING DEMAND. Progress Energy's service territories are among the fastest-growing areas of the country. The company currently serves approximately 3.1 million customers in the Carolinas and Florida, adding more than 64,000 new customers last year alone.

In addition to population growth and economic expansion, individual homes and power demands are also increasing. The average size of a home in the South has grown nearly 50 percent in the last 30 years.

To meet this growing demand, we expect to add approximately 12,500 megawatts of new generation by 2025. In fact, Progress Energy could double its size over the next 15 years simply from organic growth within our two utilities.

OUR BALANCED APPROACH. With this growing demand comes the opportunity to explore and develop the best energy solutions for the future. At Progress Energy, we believe in a balanced mix of energy efficiency, renewable energy, upgrading of existing plants and construction of new power plants.

We anticipate increased consumer interest in energy efficiency and smart energy choices as well as greater need for us to help manage both energy supply and demand. As we pursue the aggressive expansion of our energy-efficiency programs, we are aligning our strategy with our customers' best interests.

We are actively supporting the development of innovative renewable energy technologies, including plants fueled by landfill gas and animal waste, as well as cutting-edge solar and hydrogen projects.

Amy Dorsett (left), energy efficiency specialist; gives energy-saving tips during one of the 50,000 free Home Energy Checks we provide each year.

We are also modernizing our existing plants and considering plans to build new power plants. In 2006, we announced plans to potentially construct new nuclear plants in North Carolina and Florida. These large capital investment projects are a major part of our long-term strategy for meeting our customers' needs and building value for our investors.

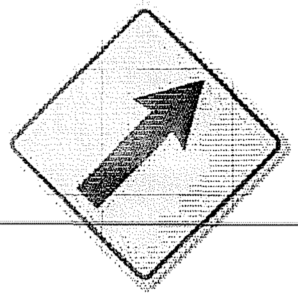
STRONG PLATFORM FOR FUTURE GROWTH. This is a time of great opportunity and possibility for Progress Energy. We are positioned to lead the industry in the pursuit of the most efficient, affordable and innovative solutions to our growing communities' energy needs.

Now, more than ever, our path is clear and our momentum is growing. And we are excited to have you with us as we move forward on *The Road Ahead.*

ENERGY FOR THE FUTURE.

The complex energy needs of the future require a balanced approach. Progress Energy is enhancing energy-efficiency programs and investing in new generation options and alternative-energy sources. In 2006, we signed a 25-year contract to purchase power generated using environmentally friendly e-grass, reducing our need for coal by nearly 9 million tons and cutting air emissions significantly.

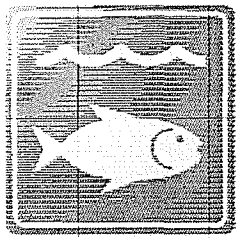
SIGNS OF PROGRESS



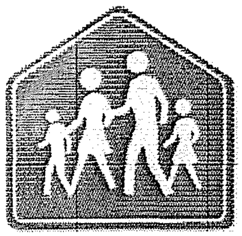
INCREASED SHAREHOLDER VALUE. Our goal is to grow earnings and dividends so we can achieve total annual shareholder returns of 8 percent to 10 percent.

INDUSTRY LEADER. In 2006, the Edison Electric Institute recognized Progress Energy as the industry leader in customer satisfaction and operational excellence with its highest award.

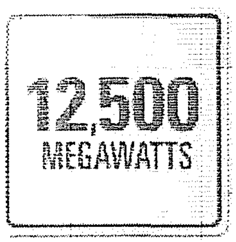
CLEAR FOCUS. After following through on our commitment to divest noncore assets, we are able to achieve a single-minded focus on our two regulated electric utilities, which reduces risk and plays to our strengths.



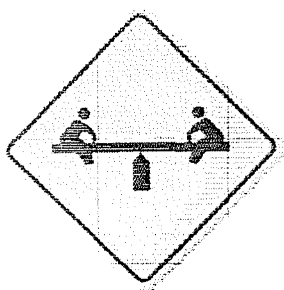
ENVIRONMENTAL STEWARDSHIP. We are investing billions to operate in an increasingly environmentally responsible way as part of our commitment to our communities.



GROWING COMMUNITIES. Our service territories are among the fastest-growing areas of the country, adding new residents and businesses at a rate significantly faster than the national average.



GROWING DEMAND. By 2025, we anticipate we'll need to add approximately 12,500 megawatts to keep up with the growth in our service areas.

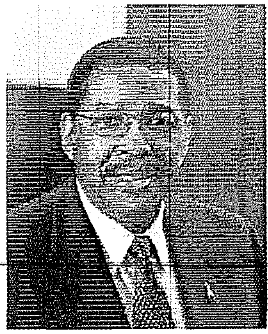


BALANCED SOLUTIONS. Balance is key to long-term energy supply. Energy efficiency, alternative energy, the modernization of existing plants and the construction of new power plants are all part of our strategy for the future.

BOARD OF DIRECTORS

Edwin B. Borden
Retired President, The Borden Manufacturing Co. (textile management services)
Goldsboro, N.C.

Elected to the board in 1985 and sits on the following committees: Corporate Governance; Organization and Compensation; Operations and Nuclear Oversight (Chair).



James E. Bostic, Jr.
Managing Director, HEP & Associates (business consulting) and retired Executive Vice President, Georgia-Pacific Corp. (manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals)
Atlanta, Ga.

Elected to the board in 2002 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.

David L. Burner
Retired Chairman and Chief Executive Officer, Goodrich Corp. (aerospace components, systems and services)
Darby, Mont.

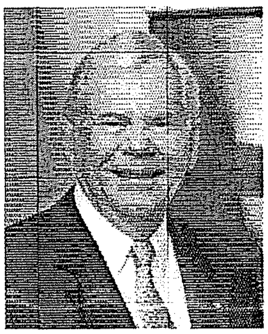
Elected to the board in 1999 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

Richard L. Daugherty
Formerly Executive Director, NCSU Research Corp., Vice President, IBM PC Company and Senior State Executive, IBM Corp.
Raleigh, N.C.

Elected to the board in 1992 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Finance.

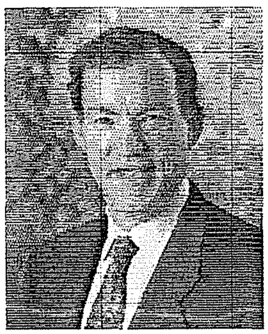
Harris E. DeLoach, Jr.
Chairman, President and Chief Executive Officer, Sonoco Products Co. (manufacturer of paperboard and paper and plastic packaging products)
Hartsville, S.C.

Elected to the board in 2006 and sits on the following committees: Operations and Nuclear Oversight; Organization and Compensation.



W. D. "Bill" Frederick, Jr.
Citrus grower and rancher, formerly mayor of Orlando and partner in the law firm of Holland & Knight
Orlando, Fla.

Elected to the board in 2000 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.



W. Steven Jones
Dean and Professor of Management of Kenan-Flagler Business School at the University of North Carolina at Chapel Hill
Chapel Hill, N.C.

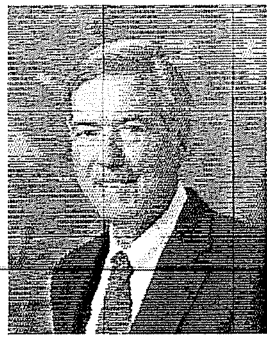
Elected to the board in 2005 and sits on the following committees: Finance; Organization and Compensation.

Robert B. McGehee
Chairman and Chief Executive Officer, Progress Energy, Inc.
Raleigh, N.C.

Elected to the board in 2004. Serves as Chairman, Progress Energy Carolinas and Chairman, Progress Energy Florida.

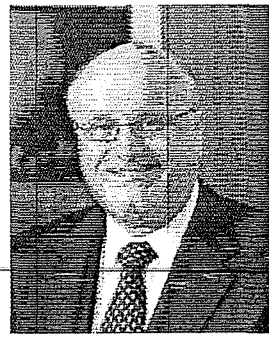
E. Marie McKee
Senior Vice President, Corning, Inc. (manufacturer of components for high-technology systems for consumer electronics, mobile emissions controls, telecommunications and life sciences) and President and Chief Executive Officer, Steuben Glass
Corning, N.Y.

Elected to the board in 1999 and sits on the following committees. Corporate Governance; Organization and Compensation (Chair); Operations and Nuclear Oversight.



John H. Mullin, III
Chairman, Ridgeway Farm, LLC (farming and timber management) and formerly a Managing Director, Dillon, Read & Co. (investment bankers)
Brookneal, Va.

Elected to the board in 1999, Lead Director and sits on the following committees: Corporate Governance (Chair); Finance; Organization and Compensation.

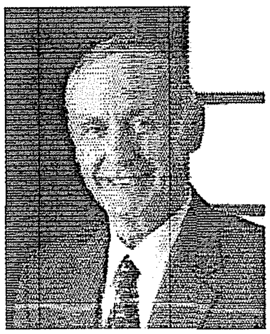


Carlos A. Saladrigas
Chairman, Premier American Bank and retired Chief Executive Officer, ADP TotalSource
Miami, Fla.

Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance; Finance.

Theresa M. Stone
Executive Vice President, Massachusetts Institute of Technology and retired President, Lincoln Financial Media (financial services company)
Boston, Mass.

Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance; Finance

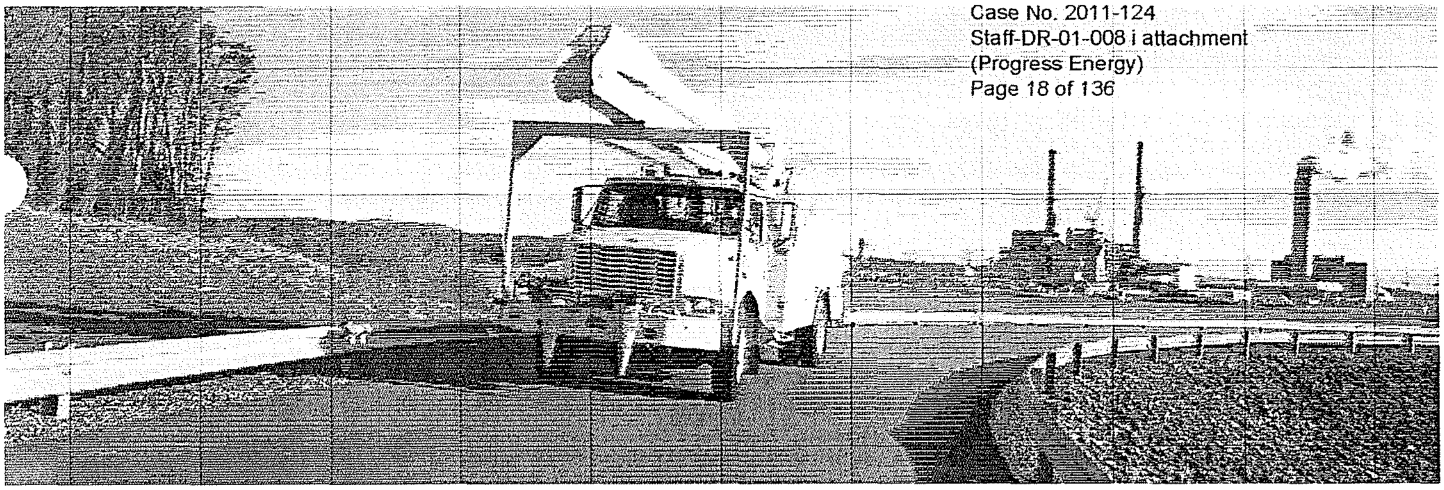


Alfred C. Tollison, Jr.
Retired Chairman and Chief Executive Officer, Institute of Nuclear Power Operations (INPO is a nuclear industry-sponsored nonprofit organization)
Marietta, Ga.

Elected to the board in 2006 and sits on the following committees. Audit and Corporate Performance; Operations and Nuclear Oversight.

Jean Giles Wittner
President and Secretary, Wittner & Co., Inc. (real estate management and insurance brokerage and consulting)
St. Petersburg, Fla.

Elected to the board in 2000 and sits on the following committees: Audit and Corporate Performance, Operations and Nuclear Oversight.



At Progress Energy, we consistently pursue excellence in all our endeavors. Our internal controls over financial reporting reflect that commitment and, as a result, Progress Energy achieved full compliance with the applicable internal control requirements in connection with its 2006 financial reporting processes.

RESPONSIBILITIES OF KEY BOARD COMMITTEES

AUDIT AND CORPORATE PERFORMANCE COMMITTEE

This committee reviews the annual and quarterly financial results of the company and the various periodic reports the company files with the SEC. It is responsible for retaining the company's external auditors, overseeing and monitoring the auditors' activities and pre-approving all external audit and non-audit services and fees. This committee also oversees the activities of the internal audit department and the Corporate Ethics Program.

CORPORATE GOVERNANCE COMMITTEE

This committee is responsible for making recommendations on the structure, charter, practices and policies of the board, including amendments to the articles of incorporation and bylaws. The committee ensures that processes are in place for annual CEO performance appraisal, reviews of succession planning and management development. It also recommends the process for the annual assessment of board performance and criteria for board membership. In addition, it proposes nominees to the board.

FINANCE COMMITTEE

This committee reviews and oversees the company's financial policies and planning and the company's pension funds. It monitors the company's financial position, reviews the company's strategic investments and financing options and recommends changes in the company's dividend policy.

OPERATIONS AND NUCLEAR OVERSIGHT COMMITTEE

This committee reviews the company's load forecasts and plans for generation, transmission and distribution, fuel procurement and transportation, customer service, energy trading, term marketing and other company operations. The committee ensures company policies, procedures and practices relative to environmental protection and safety-related issues are sufficient to achieve and maintain compliance with applicable laws and regulations, and advises and makes recommendations to the board regarding these matters.

ORGANIZATION AND COMPENSATION COMMITTEE

This committee reviews personnel policies and procedures for consistency with governmental rules and regulations and ensures that the company attracts and retains competent, talented employees. The committee reviews all executive-development and management-succession plans, evaluates CEO performance and makes senior executive compensation decisions.

EXECUTIVE AND SENIOR OFFICERS

Robert B. McGehee
Chairman and Chief Executive Officer

William D. Johnson
President and Chief Operating Officer

Peter M. Scott III
Chief Financial Officer
Progress Energy, Inc.
President and Chief Executive Officer
Progress Energy Service Company, LLC

Fred N. Day IV
President and Chief Executive Officer
Progress Energy Carolinas, Inc.

Jeffrey J. Lyash
President and Chief Executive Officer
Progress Energy Florida, Inc.

C. S. Hinnant
Senior Vice President – Nuclear Generation and Chief Nuclear Officer

Jeffrey A. Corbett
Senior Vice President – Energy Delivery
Progress Energy Florida, Inc.

John R. McArthur
Senior Vice President – Corporate Relations
General Counsel and Secretary

Mark F. Mulhern
President
Progress Energy Ventures, Inc.

Paula J. Sims
Senior Vice President – Regulated Services

E. Michael Williams
Senior Vice President – Power Operations

Lloyd M. Yates
Senior Vice President – Energy Delivery
Progress Energy Carolinas, Inc.

FINANCIAL REPORT

Certain matters discussed throughout this Annual Report that are not historical facts are forward looking and, accordingly, involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Any forward-looking statement is based on information current as of the date of this report and speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made.

In addition, examples of forward-looking statements discussed in this Annual Report include, but are not limited to, "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A) including, but not limited to, statements under the following headings: a) "Strategy" about our future strategy and goals, b) "Results of Operations" about trends and uncertainties; c) "Liquidity and Capital Resources" about operating cash flows, estimated capital requirements through the year 2009 and future financing plans; and d) "Other Matters" about our synthetic fuels facilities, the effects of new environmental regulations, nuclear decommissioning costs and the effect of electric utility industry restructuring.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and the Energy Policy Act of 2005; the financial resources and capital needed to comply with environmental laws and our ability to recover eligible costs under cost-recovery clauses; weather conditions that directly influence the production, delivery and demand for electricity; the ability to recover through the regulatory process costs associated with future significant weather events; recurring seasonal fluctuations in demand for electricity; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process, economic fluctuations and the corresponding impact on our commercial and industrial customers; the ability of our subsidiaries to pay upstream dividends or distributions to the Parent; the impact on our facilities and businesses from a terrorist attack; the inherent risks associated with the operation of nuclear facilities, including environmental, health, regulatory and financial risks, the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks, the ability to successfully access capital markets on favorable terms; our ability to maintain our current credit ratings and the impact on our financial condition and ability to meet our cash and other financial obligations in the event our credit ratings are downgraded, the impact that increases in leverage may have on us, the impact of derivative contracts used in the normal course of business; the investment performance of our pension and benefit plans; our ability to control costs, including pension and benefit expense, and achieve our cost-management targets for 2007, our ability to generate and utilize tax credits from the production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K), the impact that future crude oil prices may have on our earnings from our coal-based solid synthetic fuels businesses; the execution of our announced intent to dispose of our Competitive Commercial Operations (CCO) business and additional resulting charges to income, which could exceed $200 million; our ability to manage the risks involved with the CCO business, including dependence on third parties and related counterparty risks, until completion of our disposal strategy; the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements; and unanticipated changes in operating expenses and capital expenditures. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in our filings with the United States Securities and Exchange Commission (SEC). All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the effect of each such factor on Progress Energy.

The following Management's Discussion and Analysis contains forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review the "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein. As used in this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas and Progress Energy Florida, as the "Utilities." Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements.

INTRODUCTION

Our reportable business segments and their primary operations include:

- Progress Energy Carolinas (PEC) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina;
- Progress Energy Florida (PEF) – primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida; and
- Coal and Synthetic Fuels – primarily engaged in the production and sale of coal-based solid synthetic fuels in Kentucky and West Virginia, the operation of synthetic fuels facilities for third parties in West Virginia, and coal terminal services in Kentucky and West Virginia.

The "Corporate and Other" segment is comprised of nonregulated businesses that do not separately meet the requirements as a business segment. It primarily includes the activities of the Parent and Progress Energy Service Company, LLC (PESC), as well as other nonregulated business areas.

Strategy

We are an integrated energy company, with our primary focus on the end-use and wholesale electricity markets. We operate in retail utility markets in the southeastern United States and in other fuels markets in the eastern United States. Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. We believe that our two electric utilities, combined with our reduced nonregulated business risk, position us well for long-term growth. We are focused on the following key priorities:

- excelling in the daily fundamentals of our utility business;
- preparing for future baseload capacity due to high growth in our regulated service territories,
- further strengthening our financial flexibility and growth;
- maintaining constructive regulatory relations; and
- executing our remaining divestiture transactions.

A summary of the significant financial objectives or issues impacting us, the Utilities and our remaining nonregulated operations is addressed more fully in the following discussion.

We have several key financial objectives, the first of which is to achieve sustainable earnings growth. In addition, we seek to continue our track record of dividend growth, as we have increased our dividend for 19 consecutive years, and 31 of the last 32 years. We also seek to continue our efforts to enhance balance sheet strength and flexibility so that we are positioned to accommodate the significant future growth expected at the Utilities.

In the short term, our ability to achieve these objectives will be impacted by, among other things, our ability to manage operation and maintenance (O&M) costs, the successful execution of our remaining divestiture transactions, increased environmental spending requirements, commodity price risk, and the scheduled expiration of the Internal Revenue Code (the Code) Section 29/45K tax credit program for our synthetic fuels business at the end of 2007. Our long-term challenges include continuing our cost-management initiatives to mitigate escalating nonfuel and fuel operating costs, effectively managing capital projects, including those for environmental compliance and baseload capacity growth, achieving sufficient earnings growth to sustain our track record of dividend growth, meeting the need for future baseload capacity in our regulated service territories, achieving regulatory stability and investment recovery at the Utilities and complying with increasingly stringent environmental standards. Please review the "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

Our ability to meet these financial objectives is largely dependent on the earnings and cash flows of the Utilities. The Utilities contributed $780 million of our segment profit and generated substantially all of our consolidated cash flow from operations in 2006. Partially offsetting the net income contribution provided by the Utilities was a loss of $76 million recorded at our Coal and Synthetic Fuels operations, primarily related to the impairment of our synthetic fuels assets, and a loss of $190 million recorded at Corporate and Other, primarily related to interest expense on holding company debt.

While our synthetic fuels operations have historically provided significant net earnings driven by the Section 29/45K tax credit program, which is scheduled to expire at the end of 2007, the associated cash flow benefits from synthetic fuels are expected to come in the future when deferred tax credits are ultimately utilized. The total Section 29/45K credits that have been generated through December 31, 2006, but not yet utilized, are currently carried forward as deferred tax credits and will provide cash flow benefits when utilized. At December 31, 2006, the amount of these deferred tax credits was $847 million. See "Other Matters – Synthetic Fuels Tax Credits" below and Note 22D for additional information on our synthetic fuels operations.

Our total debt to total capitalization ratio calculated from the Consolidated Balance Sheet is 52.2 percent at the end of 2006, a decrease from 57.7 percent at the end of 2005, primarily due to a reduction in total debt with proceeds from asset sales, recovery of storm costs incurred in Florida during 2004, fuel cost recovery, operating cash flow and growth in equity from retained earnings and limited ongoing equity issuances. We expect total capital expenditures for 2007, 2008 and 2009 to be approximately $2.4 billion, $2.5 billion and $2.4 billion, respectively, primarily related to the ongoing Utilities' operations. We believe that operating cash flows plus availability under our credit facilities and shelf registration statements will be sufficient to fund our current business plans in the near term. In the long term, we expect to fund our business plans and any new baseload generation through operating cash flows and a combination of long-term debt, preferred stock and common equity, all of which are dependent on our ability to successfully access capital markets. We may also pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

In 2006, the Parent's, PEC's, and PEF's corporate credit ratings of BBB were affirmed and their ratings outlooks were changed to "positive" from "stable" by Standard & Poor's (S&P). Moody's Investors Service, Inc. (Moody's) upgraded the Parent's outlook to "stable" from "negative" and upgraded PEC's outlook to "positive" from "stable." Fitch Ratings (Fitch) upgraded the senior unsecured credit ratings of the Parent (BBB), PEC (A-) and PEF (A-), changed their ratings outlooks to "stable" and removed the Ratings Watch Positive. See "Credit Rating Matters" and "Guarantees" under "Future Liquidity and Capital Resources" below for more information regarding the potential impact on our financial condition and results of operations resulting from a ratings change.

REGULATED UTILITIES

The Utilities' earnings and operating cash flows are heavily influenced by weather, the economy, demand for electricity related to customer growth, actions of regulatory agencies, cost controls, the timing of recovery of fuel costs, and storm damage.

The Utilities operate in the southeastern United States, one of the fastest-growing regions of the country, and had a net increase of approximately 64,000 customers over the past year. However, lower industrial sales related mainly to weakness in the textile sector at PEC have reduced the rate of revenue growth in recent years. We do not expect any significant improvement or further degradation in industrial sales in the near term. These combined factors under normal weather conditions are expected to contribute approximately 1.5 percent to 2.0 percent annual retail kilowatt-hour (kWh) sales growth at PEC and approximately 2.5 percent to 3.0 percent annual retail kWh sales growth at PEF through at least 2008. The Utilities also seek to maintain their regulated wholesale business through targeted contract renewals and origination opportunities. The Utilities must continue to invest significant capital in additional energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities to support this load growth. Subject to regulatory approval, these investments are expected to increase the Utilities' "rate base" or investment in utility plant, upon which additional return can be realized that creates the basis for long-term earnings growth in the Utilities. Through 2008, we will meet this load growth at PEC through existing resources and at PEF through the previously planned combined cycle unit of approximately 500 megawatts (MW) at PEF's Hines Energy Complex in 2007. The Utilities expect total capital expenditures for 2007, 2008 and 2009 to be approximately $2 4 billion, $2.5 billion and $2.4 billion, respectively. The Utilities expect to fund their capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or contribution of equity from the Parent.

Meeting the anticipated growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: increasing energy efficiency and investing in the development of new energy resources for the future; modernizing existing plants to produce energy efficiently using state-of-the-art technology; and investing in new generating plants. We estimate that we will require new baseload generation facilities at both PEC and PEF by the middle of the next decade and a combined total of approximately 12,500 MW of additional capacity by 2025, and we are evaluating the best available options for this generation, including advanced design nuclear and clean coal technologies. The considerations that will factor into this decision include construction costs, fuel diversity, transmission and site availability, environmental impact, the rate impact to customers and our ability to obtain cost-effective financing. See "Other Matters – Nuclear Matters" for additional information.

We are subject to significant air quality regulations passed by the United States Environmental Protection Agency (EPA) in 2005 that affect our fossil fuel-fired generating facilities, the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR). Additionally, at PEC's coal-fired facilities in North Carolina, we are subject to the North Carolina Clean Smokestacks Act enacted in 2002 (Clean Smokestacks Act). Including estimated costs for CAIR, CAMR, CAVR and the Clean Smokestacks Act, we currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or pass-through clauses, could be in excess of $1 0 billion each at PEC and PEF, respectively, through 2018, which is the latest compliance target date for current air and water quality regulations.

While the Utilities expect retail sales growth in the future, they are facing, and expect to continue to face, rising costs. The Utilities are committed to continuing to effectively manage costs to minimize the expected growth in O&M expenses. The Utilities are allowed to recover prudently incurred fuel costs through the fuel portion of our rates, which are adjusted annually in each state.

We are focused on mitigating the impact of rising fuel prices since the under-recovery of fuel costs impacts our cash flows, interest and leverage, and rising fuel costs and higher rates also impact customer satisfaction. Our efforts to mitigate these high fuel costs include our diverse generation mix, staggered fuel contracts and hedging, and supplier and transportation diversity.

The Utilities successfully resolved key state regulatory issues in 2006, including fuel recovery filings in South Carolina, North Carolina and Florida and storm cost reserve replenishment in Florida. The Utilities continue to monitor progress toward a more competitive environment. No retail electric restructuring legislation has been introduced in the jurisdictions in which PEC and PEF operate. As part of the Clean Smokestacks Act, PEC is operating under a base rate freeze in North Carolina through 2007. As a result of its 2005 base rate proceeding, PEF's base rate settlement extends through 2009. See Note 7 for further discussion of the Utilities' retail rates.

NONREGULATED BUSINESSES

Our primary nonregulated businesses are Coal and Synthetic Fuels. Earnings of Coal and Synthetic Fuels are impacted largely by the volume of synthetic fuels produced and tax credits generated, and volumes and prices of coal terminal sales.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity, all of which own facilities that produce coal-based solid synthetic fuels as defined under Section 29/45K of the Code. The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility that was placed in service before July 1, 1998. Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for 2007. This possibility is due to a provision of Section 29/45K that provides that if annual average market prices for crude oil exceed certain prices, the amount of tax credits is reduced for that year. In January 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately

8 million tons of 2007 synthetic fuels production. The contracts will be marked-to-market with changes in fair value recorded through earnings. Our synthetic fuels production levels for 2007 remain uncertain because we cannot predict with any certainty the price of oil for 2007. We will continue to monitor the environment surrounding synthetic fuels production and will adjust our production or consider other alternatives as warranted by changing conditions. See additional discussion of synthetic fuels tax credits in "Application of Critical Accounting Policies and Estimates – Synthetic Fuels Tax Credits" and "Other Matters – Synthetic Fuels Tax Credits."

As discussed more fully in Note 3 and "Results of Operations – Discontinued Operations," in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, many of our nonregulated business operations have been divested or are in the process of being divested. Consequently, we no longer report a Progress Ventures segment, and the composition of other continuing segments has been impacted by these divestitures. These operations have been classified as discontinued operations in the accompanying financial statements. As of December 31, 2006, the carrying value of long-lived assets of the remaining nonregulated electric generation operations and energy marketing activities and the remaining coal mining operations and other fuels businesses was $573 million.

RESULTS OF OPERATIONS

In this section, earnings and the factors affecting earnings are discussed. The discussion begins with a summarized overview of our consolidated earnings, which is followed by a more detailed discussion and analysis by business segment

Overview

FOR 2006 AS COMPARED TO 2005 AND 2005 AS COMPARED TO 2004

For the year ended December 31, 2006, our net income was $571 million or $2.28 per share compared to $697 million or $2.82 per share for the same period in 2005. For the year ended December 31, 2006, our income from continuing operations was $514 million compared to $721 million for the same period in 2005. The decrease in income from continuing operations as compared to prior year was due primarily to:

- lower synthetic fuels earnings primarily due to lower tax credits;
- impairment of all of our synthetic fuels assets and a portion of our coal terminal assets, primarily due to high oil prices,
- unfavorable weather at the Utilities,
- the cost incurred to redeem holding company debt;
- unrealized losses recorded on contingent value obligations;
- increased nuclear outage expenses at PEC; and
- the prior year gain on the sale of our utility distribution assets serving the City of Winter Park, Fla (Winter Park).

Partially offsetting these items were:

- prior year postretirement and severance expenses related to the 2005 cost-management initiative;
- increased retail growth and usage at the Utilities;
- the gain on sale of Level 3 Communications, Inc. (Level 3) stock acquired as part of the divestiture of Progress Telecom, LLC (PT LLC); and
- the prior year write-off of unrecoverable storm costs at PEF.

For the year ended December 31, 2005, our net income was $697 million or $2.82 per share compared to $759 million or $3.13 per share for the same period in 2004. For the year ended December 31, 2005, our income from continuing operations was $721 million compared to $673 million for the same period in 2004. The increase in income from continuing operations as compared to prior year was due primarily to:

- increased synthetic fuels earnings;
- customer growth at the Utilities;
- favorable weather at the Utilities;
- increased wholesale sales at the Utilities; and
- the gain recorded on the sale of Winter Park utility distribution assets.

Partially offsetting these items were:

- postretirement and severance charges related to the 2005 cost-management initiative;
- the change in accounting estimates for certain capital costs in our distribution operations (Energy Delivery); and
- the write-off of unrecoverable storm costs at PEF.

Our segments contributed the following profit or loss from continuing operations:

(in millions)	2006	Change	2005	Change	2004
PEC	$454	$(36)	$490	$32	$458
PEF	326	68	258	(75)	333
Coal and Synthetic Fuels	(76)	(239)	163	73	90
Total segment profit	704	(207)	911	30	881
Corporate and Other	(190)	–	(190)	18	(208)
Total income from continuing operations	514	(207)	721	48	673
Discontinued operations, net of tax	57	82	(25)	(111)	86
Cumulative effect of change in accounting principle	–	(1)	1	1	–
Net income	$571	$(126)	$697	$(62)	$759

COST-MANAGEMENT INITIATIVE

On February 28, 2005, we approved a workforce restructuring that resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program. In connection with this initiative, we incurred approximately $164 million of pre-tax charges for severance and postretirement benefits during the year ended December 31, 2005. We did not incur any similar charges during 2006. The severance and postretirement charges are primarily included in O&M expense on the Consolidated Statements of Income and will be paid over time.

Progress Energy Carolinas

PEC contributed segment profits of $454 million, $490 million and $458 million in 2006, 2005 and 2004, respectively. The decrease in profits for 2006 as compared to 2005 is primarily due to the unfavorable impact of weather, higher O&M expense related to nuclear outages, the impact of suspending the allocation of the Parent's income tax benefit not related to acquisition interest expense and 2006 capital project write-offs. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. These were partially offset by postretirement and severance expenses incurred in 2005 related to the 2005 cost-management initiative and increased retail customer growth and usage.

The increase in profits for 2005 as compared to 2004 is primarily due to increased revenue from retail customer growth, the favorable impact of weather, increased wholesale margins primarily due to an increase in excess generation revenues and lower depreciation and amortization expense. These were partially offset by higher O&M charges primarily due to postretirement and severance charges related to the cost-management initiative and an increase in expenses charged to other, net.

REVENUES

PEC's electric revenues and the percentage change by year and by customer class were as follows:

(in millions) Customer Class	2006	% Change	2005	% Change	2004
Residential	$1,462	2.8	$1,422	7.4	$1,324
Commercial	1,004	6.8	940	5.9	888
Industrial	711	3.9	684	3.8	659
Governmental	91	4.6	87	6.1	82
Total retail revenues	3,268	4.3	3,133	6.1	2,953
Wholesale	720	(5.1)	759	32.0	575
Unbilled	(1)	–	4	–	10
Miscellaneous	98	4.3	94	4.4	90
Total electric revenues	4,085	2.4	3,990	10.0	3,628
Less: Fuel revenues	(1,314)	–	(1,186)	–	(929)
Revenues excluding fuel	$2,771	(1.2)	$2,804	3.9	$2,699

PEC's electric energy sales and the percentage change by year and by customer class were as follows:

(in thousands of MWh) Customer Class	2006	% Change	2005	% Change	2004
Residential	16,259	(2.4)	16,664	4.1	16,003
Commercial	13,358	0.3	13,313	2.3	13,019
Industrial	12,393	(2.5)	12,716	(2.5)	13,036
Governmental	1,419	0.6	1,410	(1.5)	1,431
Total retail energy sales	43,429	(1.5)	44,103	1.4	43,489
Wholesale	14,584	(6.9)	15,673	18.5	13,222
Unbilled	(137)	–	(235)	–	91
Total MWh sales	57,876	(2.8)	59,541	4.8	56,802

PEC's revenues, excluding fuel revenues of $1.314 billion and $1.186 billion for 2006 and 2005, respectively, decreased $33 million. The decrease in revenues was due primarily to the $67 million unfavorable impact of weather partially offset by a $24 million increase in retail customer growth and usage. Weather had an unfavorable impact as cooling degree days were 9 percent below 2005 and heating degree days were 12 percent below 2005. The increase in retail customer growth and usage was driven by an approximate increase in the average number of customers of 29,000 as of December 31, 2006, compared to December 31, 2005. Although the change in wholesale revenue less fuel did not have a material impact on the change in revenues, wholesale electric energy sales were down 6.9 percent primarily due to lower excess generation sales in 2006 compared to 2005, partially offset by an increase in contracted wholesale capacity. The decrease in excess generation sales in 2006 compared to 2005 is due to favorable market conditions during 2005 that resulted in strong sales to the mid-Atlantic United States.

PEC's revenues, excluding fuel revenues of $1.186 billion and $929 million for 2005 and 2004, respectively, increased $105 million. The increase in revenues was primarily due to increased retail revenues of $22 million as a result of favorable weather, with cooling degree days 6 percent above prior year. Retail customer growth contributed an additional $46 million in revenues in 2005. PEC's retail customer base increased as approximately 30,000 net new customers were added during 2005. Wholesale revenues, excluding fuel revenues, increased $37 million when compared to $311 million in 2004. The increase in PEC's wholesale revenues in 2005 from 2004 is primarily the result of increased excess generation sales. Revenues for 2005 included strong sales to the mid-Atlantic United States as a result of favorable market conditions. In addition, higher contracted capacity compared to 2004 further increased wholesale revenues.

Industrial electric energy sales decreased in 2006 compared to 2005 primarily due to continued reduction in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation. Industrial electric energy sales decreased in 2005 when compared to 2004 primarily due to the reduction in textile manufacturing in the Carolinas and lower demand for both pulp and paper products. The increase in industrial revenues for 2006 compared to 2005 and 2005 compared to 2004 is due to an increase in fuel revenues as a result of higher energy costs and the recovery of prior year fuel costs.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchases for generation, as well as energy purchased in the market to meet customer load. Fuel and a portion of purchased power expenses are recovered primarily through cost-recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection from or refund to customers.

Fuel and purchased power expenses were $1.507 billion for 2006, which represents a $117 million increase compared to 2005. Fuel used in electric generation increased $137 million to $1.173 billion compared to 2005. This increase is due to a $141 million increase in deferred fuel expense partially offset by a $5 million decrease in fuel used in generation. Deferred fuel expense increased as a result of an increase in North Carolina and South Carolina fuel recovery rates. Fuel used in generation decreased primarily due to lower system requirements. Purchased power expenses decreased $20 million to $334 million compared to prior year. The decrease in purchased power is due primarily to a change in volume as a result of lower system requirements.

Fuel and purchased power expenses were $1.390 billion for 2005, which represents a $253 million increase compared to 2004. Fuel used in electric generation increased $200 million to $1.036 billion compared to 2004. This increase was due to a $308 million increase in fuel used in generation due to higher fuel costs, a change in generation mix and increased volume. Higher fuel costs were driven primarily by an increase in coal and natural gas prices. Outages at several facilities during 2005 resulted in increased combustion turbine generation, which had a higher average fuel cost. The increase in fuel used in generation was offset by a reduction in deferred fuel expense as a result of the under-recovery of 2005 fuel costs. Purchased power expenses increased $53 million to $354 million compared to 2004. The increase in purchased power was due primarily to a change in volume partially offset by a decrease in price

Operation and Maintenance

O&M expenses were $930 million for 2006, which represents an $11 million decrease compared to 2005. This decrease is driven primarily by the $55 million impact of postretirement and severance expenses incurred in 2005 related to the cost-management initiative partially offset by $30 million of higher 2006 outage expenses at nuclear plants and capital project write-offs of $16 million in 2006

O&M expenses were $941 million for 2005, which represents a $70 million increase compared to 2004. This increase was driven primarily by postretirement and severance expenses related to the 2005 cost-management initiative. Postretirement and severance expenses related to the cost-management initiative increased O&M expenses by $53 million during 2005. This increase included $55 million of charges in 2005 compared to 2004 expenses, which included $2 million related to a separate initiative. In addition, O&M expenses increased $26 million related to the change in accounting estimates for certain Energy Delivery capital costs, $25 million for higher emission allowance expenses, $16 million related to pension expenses and $6 million related to Hurricane Ophelia storm restoration costs in 2005. These unfavorable items were partially offset by decreased plant outage costs of $12 million compared to 2004, which included an additional nuclear plant outage, $8 million of lower health and life benefit expenses and a $6 million reduction of surplus inventory expense. In addition, results for 2004 included $19 million of costs associated with an ice storm that impacted the Carolinas service territory in the first quarter of 2004 and Hurricanes Charley and Ivan that impacted the Carolinas service territory in the third quarter of 2004.

Depreciation and Amortization

Depreciation and amortization expense was $571 million for 2006, which represents a $10 million increase compared to 2005. This increase is primarily attributable to the $12 million impact of depreciable asset base increases and $3 million of deferred environmental cost amortization partially offset by a $7 million decrease in the Clean Smokestacks Act amortization. We recorded $140 million of Clean Smokestacks Act amortization during 2006 compared to $147 million in 2005.

Depreciation and amortization expense was $561 million for 2005, which represents a $9 million decrease compared to 2004. This decrease was primarily attributable to the Clean Smokestacks Act amortization decrease of $27 million to $147 million in 2005 compared to amortization of $174 million in 2004. This was partially offset by higher depreciation expense of $17 million for increases in the depreciable asset base.

Taxes Other than on Income

Taxes other than on income were $191 million for 2006, which represents a $13 million increase compared to 2005. This increase is primarily due to a $7 million increase in property taxes and a $6 million increase in gross receipts taxes related to higher revenue. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Taxes other than on income were $178 million for 2005, which represents a $5 million increase compared to 2004 primarily due to higher payroll taxes of $5 million.

Other

Other operating expenses consisted of a gain of $1 million in 2006 compared to a gain of $11 million in 2005, and a gain of $12 million in 2004. The decrease in the 2006 gain is primarily due to fewer land sales.

Total Other Income (Expense)

Total other income (expense) was $50 million of income for 2006, which represents a $57 million increase compared to 2005. This increase is primarily due to the $32 million impact of reclassifying $16 million of indemnification liability expenses incurred in 2005 for estimated capital costs associated with the Clean Smokestacks Act expected to be incurred in excess of the maximum billable costs to the joint owner. This expense was reclassified to Clean Smokestacks Act amortization and had no impact on 2006 earnings (See Note 21B). Interest income increased $17 million for 2006 compared to 2005 primarily due to investment interest and interest on under-recovered fuel costs. In addition, the change in other income (expense) includes a $4 million favorable impact related to recording an audit settlement with the Federal Energy Regulatory Commission (FERC) in 2005.

Total other income (expense) was $7 million of expense in 2005 compared to $3 million of income for 2004. The $10 million increase in expense for 2005 compared to 2004 was primarily due to the $16 million indemnification liability discussed above and $4 million related to an audit settlement with the FERC. These were partially offset by a $7 million write-off of nontrade receivables in 2004.

Total Interest Charges, Net

Total interest charges, net were $215 million for 2006, which represents a $23 million increase compared to 2005. This increase is primarily due to the $20 million impact of a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $265 million, $239 million and $239 million in 2006, 2005 and 2004, respectively. The $26 million income tax expense increase in 2006 compared to 2005 is primarily due to the allocation of $23 million of the Parent's tax benefit not related to acquisition interest expense in 2005 that is no longer allocated in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. Other fluctuations in income taxes are primarily due to changes in pre-tax income.

Progress Energy Florida

PEF contributed segment profits of $326 million, $258 million and $333 million in 2006, 2005 and 2004, respectively. The increase in profits for 2006 as compared to 2005 is primarily due to the impact of postretirement and severance costs incurred in 2005, increased retail customer growth and usage, an increase in rental and other miscellaneous service revenues and the impact of the 2005 write-off of unrecoverable storm costs. These were partially offset by the 2005 gain on the sale of the utility distribution assets serving Winter Park, the unfavorable impact of weather on revenues and the impact of suspending the allocation of the Parent's tax benefit not related to acquisition interest expense. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006.

The decrease in 2005 profits as compared to 2004 is primarily due to higher O&M expenses (as a result of postretirement and severance costs, the change in accounting estimates for certain Energy Delivery capital costs, the write-off of unrecoverable storm costs and costs associated with outages) and lower average usage per retail customer partially offset by the favorable impact of weather, higher wholesale sales, the gain on the sale of the utility distribution assets serving Winter Park, and increased retail customer growth.

REVENUES

PEF's electric revenues and the percentage change by year and by customer class were as follows:

(in millions)

Customer Class	**2006**	% Change	2005	% Change	2004
Residential	**$2,361**	18.0	$2,001	10.8	$1,806
Commercial	**1,152**	21.5	948	11.1	853
Industrial	**346**	21.8	284	11.8	254
Governmental	**301**	24.4	242	14.7	211
Revenue sharing refund	**1**	–	(1)	–	(11)
Total retail revenues	**4,161**	19.8	3,474	11.6	3,113
Wholesale	**319**	(7.3)	344	28.4	268
Unbilled	**(5)**	–	(6)	–	7
Miscellaneous	**164**	14.7	143	4.4	137
Total electric revenues	**4,639**	17.3	3,955	12.2	3,525
Less:					
Fuel and other pass-through revenues	**(3,038)**	–	(2,385)	–	(2,007)
Revenues excluding fuel	**$1,601**	2.0	$1,570	3.4	$1,518

PEF's electric energy sales and the percentage change by year and by customer class were as follows

(in thousands of MWh)

Customer Class	**2006**	% Change	2005	% Change	2004
Residential	**20,021**	0.6	19,894	2.8	19,347
Commercial	**11,975**	0.3	11,945	1.8	11,734
Industrial	**4,160**	0.5	4,140	1.7	4,069
Governmental	**3,276**	2.4	3,198	5.1	3,044
Total retail energy sales	**39,432**	0.7	39,177	2.6	38,194
Wholesale	**4,533**	(17.0)	5,464	7.1	5,101
Unbilled	**(234)**	–	(205)	–	358
Total MWh sales	**43,731**	(1.6)	44,436	1.8	43,653

PEF's revenues, excluding fuel and other pass-through revenues of $3.038 billion and $2.385 billion for 2006 and 2005, respectively, increased $31 million. The increase in revenues is due to increased retail customer growth and usage of $25 million and a $21 million increase in rental and other miscellaneous service revenues partially offset by a $13 million unfavorable impact of weather. The increase in retail customer growth and usage was driven by an approximate increase in the average number of customers of 35,000 as of December 31, 2006, compared to December 31, 2005. The weather impact is primarily due to a 16 percent decrease in heating degree days compared to 2005.

PEF's revenues, excluding fuel and other pass-through revenues of $2.385 billion and $2.007 billion for 2005 and 2004, respectively, increased $52 million. The increase in revenues was due in part to favorable weather in 2005 of $16 million with cooling degree days 11 percent higher than 2004. Retail customer growth contributed an additional $21 million as the approximate average number of customers increased 30,000 as of December 31, 2005, compared to 2004, and there was a significant reduction in hurricane-related customer outages compared to 2004. This growth in retail revenues was offset by lower retail revenues of $10 million in the Winter Park area due to the sale of the related distribution system in 2005 and an $8 million decline in average use per customer. Wholesale revenues net of fuel increased $18 million attributed to new contracts, including the service to Winter Park resulting from the switching of the sales to these customers from retail to wholesale. Revenues were also favorably impacted by a reduction in the provision for revenue sharing of $10 million and higher miscellaneous revenues of $6 million.

EXPENSES

Fuel and Purchased Power

Fuel and purchased power costs represent the costs of generation, which include fuel purchased for generation, as well as energy and capacity purchased in the market to meet customer load. Fuel, purchased power and capacity expenses are recovered primarily through cost-recovery clauses, and, as such, changes in these expenses do not have a material impact on earnings. The difference between fuel and purchased power costs incurred and associated fuel revenues that are subject to recovery is deferred for future collection from or refund to customers.

Fuel and purchased power expenses were $2.601 billion in 2006, which represents a $584 million increase compared to 2005. Fuel used in electric generation increased $512 million due to a $552 million increase in deferred fuel expense resulting from an increase in the fuel recovery rates on January 1, 2006. This was partially offset by a $41 million decrease in current year fuel costs due primarily to lower system requirements. Purchased power expense increased $72 million primarily due to a $48 million increase in current year purchased power costs resulting from higher market prices and a $23 million increase in the recovery of deferred capacity costs.

Fuel and purchased power expenses were $2.017 billion in 2005, which represents a $275 million increase compared to 2004. This increase was due to increases in fuel used in electric generation and purchased power expenses of $148 million and $127 million, respectively. Higher system requirements and increased fuel costs in 2005 accounted for $342 million of the increase in fuel used in electric generation. The increase in fuel used in generation was offset by a reduction in deferred fuel expense as a result of the under-recovery of 2005 fuel costs. Purchased power increased primarily due to higher prices of purchases in 2005 as a result of increased fuel costs.

Operation and Maintenance

O&M expenses were $684 million in 2006, which represents a $168 million decrease compared to 2005. The decrease is primarily due to a $102 million impact of postretirement and severance costs associated with the cost-management initiative in 2005, $24 million of lower environmental cost-recovery expenses due to a decrease in emission allowances and lower recovery rates, $17 million related to the 2005 write-off of unrecoverable storm restoration costs (See Note 7C), a $9 million decrease in nuclear outage costs and a $6 million impact related to the 2005 write-off of GridFlorida regional transmission organization (RTO) startup costs that were previously recovered in revenues. The environmental cost-recovery expenses are recovered through an environmental cost-recovery clause and, therefore, have no material impact on earnings.

O&M expenses were $852 million in 2005, which represents a $222 million increase when compared to 2004. Postretirement and severance costs associated with the cost-management initiative increased O&M costs by $102 million during 2005. In addition, PEF wrote off $17 million of unrecoverable storm costs associated with the 2004 hurricanes (See Note 7C). O&M expense also increased $37 million primarily related to the change in accounting estimates for certain Energy Delivery capital costs and increased $26 million due to higher environmental cost-recovery expenses (primarily emission allowances). The remaining increase in O&M expense is attributable to $9 million of expenses related to outages in 2005, an $8 million workers' compensation benefit adjustment recorded in 2005, $6 million related to the 2005 write-off of GridFlorida RTO startup costs that were previously recovered, and $5 million of additional bad debt expense.

Depreciation and Amortization

Depreciation and amortization expense was $404 million for 2006, which represents an increase of $70 million compared to 2005, primarily due to a $72 million increase in the amortization of storm restoration costs (See Note 7C) and a $48 million increase in utility plant depreciation partially offset by a $51 million decrease in expenses related to cost of removal primarily due to rate changes resulting from the 2005 depreciation study effective January 1, 2006 (See Note 5D). Storm restoration cost amortization is recovered in revenues through the storm recovery surcharge and, therefore, has no material impact on earnings.

Depreciation and amortization expense was $334 million for 2005, which represents an increase of $53 million compared to 2004 primarily due to the amortization of $50 million in storm restoration costs that began in August 2005 (See Note 7C).

Taxes Other than on Income

Taxes other than on income were $309 million in 2006, which represents an increase of $30 million compared to 2005. This increase is primarily due to $18 million of higher gross receipts taxes and $14 million of higher franchise taxes, related to an increase in revenues, partially offset by lower payroll taxes. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Taxes other than on income were $279 million in 2005, which represents an increase of $25 million compared to 2004. This increase was due to increases in gross receipts and franchise taxes of $8 million each, related to an increase in revenues, a $5 million increase in payroll taxes and an increase in property taxes of $3 million.

Other

Other operating expenses were a gain of $2 million in 2006 compared to a gain of $26 million in 2005 and a gain of $2 million in 2004. Both the decrease in the gain for 2006 compared to 2005 and the increase in the gain from 2005 compared to 2004 are primarily due to the $24 million gain on the sale of the utility distribution assets serving Winter Park recorded in 2005.

Total Other Income

Total other income was $28 million for 2006, which represents a $20 million increase compared to 2005. This increase is primarily due to $8 million of increased investment interest income and $6 million of interest on unrecovered storm restoration costs.

Total Interest Charges, Net

Total interest charges, net were $150 million in 2006, which represents an increase of $24 million compared to 2005. The increase in interest charges is primarily due to the $20 million impact of a net increase in average long-term debt.

Total interest charges, net were $126 million in 2005, which represents an increase of $12 million compared to 2004. The increase in interest expense was primarily due to increased commercial paper borrowings and a net increase in average long-term debt.

Income Tax Expense

Income tax expense was $193 million, $121 million and $174 million in 2006, 2005 and 2004, respectively. The $72 million income tax expense increase in 2006 compared to 2005 is primarily due to changes in pre-tax income. In addition, 2005 income tax expense included the allocation of $13 million of the Parent's tax benefit not related to acquisition interest expense that is no longer allocated in 2006. See Corporate and Other below for additional information on the change in the tax benefit allocation in 2006. Fluctuations in income tax expense between 2005 and 2004 are primarily due to changes in pre-tax income.

Coal and Synthetic Fuels

The operations of the Coal and Synthetic Fuels segment include synthetic fuels production and coal terminal operations. The following summarizes the Coal and Synthetic Fuels segment profits.

(in millions)	**2006**	2005	2004
Synthetic fuels operations	**$(44)**	$155	$92
Coal terminals and marketing	**12**	43	34
Corporate overhead and other operations	**(44)**	(35)	(36)
Segment (loss) profits	**$(76)**	$163	$90

SYNTHETIC FUELS OPERATIONS

The production and sale of synthetic fuels generate operating losses, but qualify for tax credits under Section 29/45K, which generally more than offset the effect of such losses (See "Other Matters – Synthetic Fuels Tax Credits" below).

Results from the synthetic fuels operations are summarized below:

(in millions)	**2006**	2005	2004
Tons sold	**3.7**	10.1	8.3
After-tax losses (excluding impairment charge, valuation allowance and tax credits)	**$(68)**	$(147)	$(128)
After-tax gain on sale of assets	**3**	20	5
After-tax impairment charge	**(45)**	–	–
Net operating loss (NOL) valuation allowance	**(13)**	–	–
Tax credits generated	**107**	267	215
Tax credit inflation adjustment	**10**	5	–
Tax credit reserve increase due to estimated phase-out	**(38)**	–	–
Tax credits previously unrecorded	**–**	10	–
Net (loss) profit	**$(44)**	$155	$92

Prior to 2006, our synthetic fuels production levels and the amount of tax credits we could claim each year were limited by our consolidated regular federal income tax liability. With the redesignation of Section 29 tax credits as Section 45K general business credits, that limitation was removed effective January 1, 2006.

Synthetic fuels operations' net (loss) profit changed from a profit of $155 million in 2005 to a loss of $44 million in 2006 primarily due to lower synthetic fuels production as a result of high oil prices, which increased the potential phase-out of tax credits. The 6.4 million ton decrease in synthetic fuels production resulted in $79 million of lower after-tax losses. The decision to idle our synthetic fuels facilities necessitated an impairment test and resulted in the impairment of our synthetic fuels assets (See Notes 8 and 9). The lower production also resulted in a $160 million reduction in generated tax credits, and as a result of the high oil prices, we recorded a $38 million tax credit reserve due to the estimated phase-out. The higher 2006 average oil prices and the uncertainty of the final phase-out percentage for 2006 resulted in a $17 million after-tax decrease in our gain on sale of assets due to recognizing a lower gain on the monetization of the Colona Synfuel Limited Partnership, LLLP (Colona) facility compared to 2005 (See Note 3J). The gain for 2006 is expected to be recorded in 2007 when the final phase-out percentage has been calculated. As of December 31, 2006, $7 million of deferred gain was recorded on the Consolidated Balance Sheet. In addition, results were unfavorably impacted by the recognition of a valuation allowance recorded against the deferred tax assets for state operating loss carry forwards. Due to the impairment of our synthetic fuels assets, the impairment charge included approximately $12 million of depreciation and amortization expense that would otherwise have been recorded in 2006, and $25 million of depreciation and amortization expense that would otherwise have been recorded during 2007.

Synthetic fuels operations' net (loss) profits increased in 2005 as compared to 2004 due primarily to an increase in synthetic fuels production and an additional $23 million pre-tax gain recognized on the monetization of the Colona facility compared to 2004 (See Note 3J), partially offset by an increase in operating expenses. In addition, earnings in 2005 include a $10 million favorable tax credit true-up related to 2004. Our total synthetic fuels production of approximately 10 million tons in 2005 is greater than 2004 production levels of approximately 8 million tons as a result of hurricane costs in 2004, which reduced our projected 2004 regular tax liability and our corresponding ability to record tax credits from synthetic fuels production.

Our future synthetic fuels production levels for 2007 remain uncertain due to the recent volatility of oil prices. See "Other Matters – Synthetic Fuels Tax Credits" below for additional information on the impact of oil prices on Section 29/45K tax credits, the results of our interim impairment review and a discussion of uncertainties surrounding our synthetic fuels production in 2007.

COAL TERMINALS AND MARKETING

Coal terminals and marketing (Coal) operations blend and transload coal as part of the trucking, rail and barge network for coal delivery. This business also has an operating fee agreement with our synthetic fuels operations for procuring and processing of coal and the transloading and marketing of synthetic fuels. As a result of the relationship with the synthetic fuels operations, fluctuations in Coal's annual earnings are primarily related to production volumes at our synthetic fuels facilities. Coal operations contributed earnings of $12 million, $43 million and $34 million in 2006, 2005 and 2004, respectively. Coal's 2006 results were negatively impacted by the impairment of a portion of Coal's terminal assets, which resulted in a pre-tax charge of $17 million ($10 million after-tax) and lower revenues related to lower production at our synthetic fuels facilities and higher cost of sales due to higher coal prices (See Note 9). These were partially offset by an $11 million pre-tax reduction in expense related to a restructured coal supply contract due to 2005 coal commitments that were not delivered. During the first quarter of 2006, one of Coal's supply contracts was restructured resulting in a payment of $103 million to Coal. These proceeds covered long-term coal supply commitments from 2005 through 2007 and will be recognized over the life of the contract as coal is received and the related inventory is utilized. Future amortization of these proceeds will be wholly offset by the increased contract price and is therefore not expected to materially impact earnings. As a result of the impairment of Coal's terminal assets discussed above, the impairment charge included approximately $6 million of depreciation expense that would otherwise have been recorded in 2006, and approximately $11 million of depreciation expense that would otherwise have been recorded during 2007. The Coal and Synthetic Fuels segment has long-term fixed price coal purchase contracts to provide a portion of the feedstock coal required to meet 2007 solid synthetic fuels production or to resell as coal. As a result, the 2006 decline in coal prices is expected to negatively impact the financial performance of the Coal and Synthetic Fuels segment compared to previous years.

The increase in earnings for 2005 compared to 2004 was primarily due to additional revenues at the coal terminals related to increased prices and volumes and additional intersegment fees for both the coal terminals and marketing operations due to increased synthetic fuels production. These were partially offset by an increase in the cost of coal purchased by the coal terminals operations due to increased prices and larger volumes and lower third-party sales by the marketing operations.

CORPORATE OVERHEAD AND OTHER OPERATIONS

Corporate overhead and other operations incurred losses of $44 million, $35 million and $36 million for the years ended December 31, 2006, 2005 and 2004, respectively. The increase in losses for 2006 compared to 2005 is primarily due to the decreased allocation of interest and overheads to discontinued operations as a result of the divestitures completed during 2006.

Corporate and Other

The Corporate and Other segment consists of the operations of the Parent, PESC and other consolidating and nonoperating entities (Corporate). Corporate and Other also includes other nonregulated business areas. Corporate and Other income (expense) is summarized below:

(in millions)	**2006**	Change	2005	Change	2004
Other interest expense	**$(246)**	$(12)	$(234)	$6	$(240)
Contingent value obligations	**(25)**	(31)	6	(3)	9
Tax reallocation	**–**	38	(38)	(1)	(37)
Other income tax benefit	**109**	26	83	(21)	104
Other expense	**(28)**	(21)	(7)	37	(44)
Corporate and Other after-tax expense	**$(190)**	$–	$(190)	$18	$(208)

Other interest expense, which includes elimination entries, increased $12 million for 2006 compared to 2005 primarily due to a decrease in the interest allocated to discontinued operations and a decrease in the elimination of intercompany interest expense due to lower intercompany debt balances partially offset by lower interest expense due to lower holding company debt. The decrease in interest expense allocated to discontinued operations resulted from the full year allocations of interest expense in 2005 compared to partial year allocations of interest in 2006 for operations that were sold in 2006. The decrease in other interest expense for 2005 compared to 2004 is primarily due to the increase in the interest allocated to discontinued operations partially offset by a decrease in interest rate swap activity that benefited from lower variable rates during 2004.

Progress Energy issued 98.6 million contingent value obligations (CVOs) in connection with the acquisition of Florida Progress Corporation (Florida Progress) in 2000. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities owned by Progress Energy. The payments, if any, are based on the net after-tax cash flows the facilities generate. At December 31, 2006, 2005 and 2004, the CVOs had a fair market value of approximately $32 million, $7 million and $13 million, respectively. Progress Energy recorded an unrealized loss of $25 million for 2006 and unrealized gains of $6 million and $9 million for 2005 and 2004, respectively, to record the changes in fair value of CVOs, which had average unit prices of $0.33, $0.07 and $0.14 at December 31, 2006, 2005 and 2004, respectively.

For the year ended December 31, 2006, income tax expense was not increased by the allocation of the Parent's income tax benefits not related to acquisition interest expense to profitable subsidiaries. Due to the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA 1935), beginning in 2006 we no longer allocate the Parent income tax benefits not related to acquisition interest expense to profitable subsidiaries. Since 2002, Parent income tax benefits not related to acquisition interest expense were allocated to profitable subsidiaries, in accordance with a PUHCA 1935 order. For the years ended December 31, 2005 and 2004, income tax expense was increased by $38 million and $37 million, respectively, due to the allocation of the Parent's income tax benefit.

Other income tax benefit increased for 2006 compared to 2005 primarily due to increased pre-tax expense at the Parent. Other income tax benefit decreased for 2005 compared to 2004 due primarily to lower pre-tax expense at the Parent.

For 2006, other expense was $28 million compared to $7 million in 2005. The $21 million change is primarily due to the $59 million pre-tax ($35 million after-tax) loss on redemption of holding company debt (See Note 12) partially offset by the $17 million pre-tax gain, net of minority interest, on the sale of Level 3 stock subsequent to the sale of PT LLC (See Note 3D). In addition, other expense changed due to a $14 million increase in interest income on temporary investments due to proceeds from the sale of DeSoto County Generating Co., LLC (DeSoto), Rowan County Power, LLC (Rowan) and Gas. The $37 million decrease in other expense from 2004 to 2005 was primarily due to the $43 million pre-tax ($29 million after-tax) settlement agreement in 2004 that our subsidiary Strategic Resource Solutions Corp. reached with the San Francisco United School District related to civil proceedings.

Discontinued Operations

Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses. We divested, or announced divestitures, of multiple nonregulated businesses during 2006 in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities. Consequently, we no longer report a Progress Ventures segment, and the composition of other continuing segments has been impacted by these divestitures.

CCO OPERATIONS

CCO – Georgia Operations

On December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of Progress Energy Ventures, Inc.'s (PVI) Competitive Commercial Operations (CCO) physical and commercial assets, which include approximately 1,900 megawatts of power generation facilities in Georgia, as well as forward gas and power contracts, gas transportation, storage and structured power and other contracts, including full requirement contracts with 16 Georgia Electric Membership Cooperatives (the Georgia Contracts). We expect to complete the disposition plan in 2007. As a result of the disposition plan, we recorded an after-tax estimated loss on the sale of $226 million in December 2006, which includes an impairment charge related to the generation assets and intangible assets to reduce the carrying value of the assets that are expected to be sold to their estimated fair value less cost to sell (See Note 3A).

In 2007, we anticipate recording additional material charges in discontinued operations related to the disposition plan. These additional charges relate primarily to costs to be incurred to exit the Georgia Contracts. These costs could exceed $200 million after-tax. If CCO divests of its generation facilities but not the Georgia Contracts, CCO will continue to fulfill the contractual obligation through tolling agreements or purchases in the spot market.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 billion cubic feet (Bcf) of natural gas would be fulfilled. Therefore, these contracts were no longer treated as hedges and were dedesignated, and cash flow hedge accounting was discontinued. Changes in market prices since inception resulted in the recognition of unrealized mark-to-market gains of $92 million pre-tax ($60 million after-tax) for 2006. Future price volatility in the natural gas market will cause us to record mark-to-market changes through earnings of discontinued operations and will increase the volatility of future CCO operating results.

CCO's operations generated net losses from discontinued operations of $57 million in 2006, $54 million in 2005 and $23 million in 2004. The increase in loss for 2006 compared to 2005 is primarily due to the $64 million pre-tax impairment loss ($42 million after-tax) on goodwill recognized in the first quarter of 2006 (See Note 8) and an increase in realized mark-to-market losses on gas hedges due to gas price volatility. This was partially offset by a higher gross margin related to serving the fixed price full requirements contracts that began in April 2005 and serving an increased load on a pre-existing contract in Georgia, and $66 million pre-tax of unrealized mark-to-market gains, primarily related to the dedesignated natural gas hedges discussed above.

The increase in loss for 2005 compared to 2004 is due primarily to a reduction in gross margin of $79 million pre-tax ($47 million after-tax) partially offset by favorable amortization and interest expense fluctuations. Contract margins were unfavorable in 2005 compared to 2004 due to the expiration of certain above-market tolling agreements and decreased earnings from new and existing full requirements contracts due to higher fuel and purchased power costs partially offset by net realized and unrealized mark-to-market gains. Depreciation and amortization expenses decreased $6 million pre-tax ($4 million after-tax) as a result of the expiration of certain acquired contracts that were subject to amortization.

CCO – DeSoto and Rowan Generation Facilities

On May 2, 2006, our board of directors approved a plan to divest of our DeSoto and Rowan subsidiaries. DeSoto and Rowan were subsidiaries of Progress Energy Ventures, Inc. DeSoto owns a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owns a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for a gross purchase price of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes (See Note 3C).

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. We recorded an after-tax loss of $67 million during the year ended December 31, 2006, on the sale of DeSoto and Rowan. Discontinued DeSoto and Rowan operations had combined earnings of $10 million, $3 million and $8 million for the years ended December 31, 2006, 2005 and 2004, respectively.

GAS OPERATIONS

On July 12, 2006, our board of directors approved a plan to divest of our natural gas drilling and production business (Gas), which includes Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd., all are subsidiaries of Progress Fuels Corporation (Progress Fuels). On July 22, 2006, we entered into a definitive agreement to sell Gas to EXCO Resources, Inc. for $1.2 billion in gross cash proceeds. We recorded an after-tax gain of $300 million during the year ended December 31, 2006, on the sale of Gas. Proceeds from the sale were used primarily to reduce holding company debt and for other corporate purposes (See Note 3B).

The transaction closed on October 2, 2006. Specific assets included over 325 Bcf equivalent of proved natural gas reserves, over 350 miles of pipelines, over 500 producing wells and other related assets, all of which were located in Texas and Louisiana. Discontinued Gas operations had net earnings from discontinued operations of $82 million for the year ended December 31, 2006, compared to net earnings from discontinued operations of $48 million for the same period in 2005. The increase in net earnings is primarily due to increased production, higher market prices and mark-to-market gains on gas hedges.

Gas operations generated profits of $48 million for the same period in 2005 compared to $76 million for the year ended December 31, 2004. The decrease is primarily due to the gain recognized on the sale of gas assets in 2004. In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production (North Texas gas operations). Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting the pre-tax gain of $56 million ($31 million net of taxes) was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. In addition, lower sales and general and administrative expense and interest expenses partially offset by lower revenues reduced the overall earnings decline from 2004 to 2005. Revenues were lower in 2005 due to the sale of the North Texas gas operations; however, the Texas/Louisiana gas operations were able to offset a majority of the lost revenue due to higher natural gas prices and increased production.

PROGRESS TELECOM, LLC

On March 20, 2006, we completed the sale of PT LLC to Level 3. We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC (See Note 3D).

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an estimated after-tax gain on disposal of $28 million during the year ended December 31, 2006. Net (loss) earnings from discontinued operations for PT LLC were a loss of $2 million, earnings of $4 million and a loss of $7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

DIXIE FUELS AND OTHER FUELS BUSINESS

On March 1, 2006, we sold our 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units under long-term contracts with PEF. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River Facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels. The other fuels business is expected to be sold in 2007 (See Note 3E).

Net earnings from discontinued operations for Dixie Fuels and other fuels business were $7 million, $5 million and $2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

COAL MINING BUSINESSES

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels engaged in the coal mining business. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an estimated after-tax loss of $10 million for the sale of these assets. The remaining coal mining operations are expected to be sold in 2007 (See Note 3F).

Net losses from discontinued operations for the coal mining business were $4 million, $11 million and $5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

PROGRESS RAIL

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. During the years ended December 31, 2006 and 2005, we recorded an estimated after-tax loss for the sale of these assets of $6 million and $25 million, respectively. Proceeds from the sale were used to reduce debt (See Note 3G).

Net earnings from discontinued operations for Rail were $5 million and $29 million for the years ended December 31, 2005 and 2004. Rail did not have a material impact on earnings for the year ended December 31, 2006.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We prepared our Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America. In doing so, we made certain estimates that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on our financial results and are subject to the greatest amount of subjectivity. We have discussed the development and selection of these critical accounting policies with the Audit and Corporate Performance Committee (Audit Committee) of our board of directors.

Utility Regulation

As discussed in Note 7, our regulated utilities segments are subject to regulation that sets the prices (rates) we are permitted to charge customers based on the costs that regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by a nonregulated company. This ratemaking process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the different ratemaking processes in each state in which we operate, a significant amount of regulatory assets has been recorded. We continually review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. Additionally, the state regulatory agencies often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets. See Note 7 for additional information related to the impact of utility regulation on our operations.

Asset Impairments

As discussed in Note 9, we evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever indicators exist. Examples of these indicators include current period losses combined with a history of losses, a projection of continuing losses, a significant decrease in the market price of a long-lived asset group, or the likelihood that an asset group will be disposed of significantly prior to the end of its useful life. If an indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. Performing an impairment test on long-lived assets involves management's judgment in areas such as identifying circumstances indicating an impairment may exist, identifying and grouping affected assets at the appropriate level, and developing the undiscounted cash flows associated with the asset group. Estimates of future cash flows contemplate factors such as expected use of the assets, future production and sales levels, and expected fluctuations of prices of commodities sold and consumed. Therefore, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

The carrying value of our total utility plant, net is $15.245 billion at December 31, 2006. The carrying value of our total diversified business property, net is $31 million at December 31, 2006. In addition, we have certain diversified business property with a carrying value of $573 million at December 31, 2006, included in net assets of discontinued operations (See Note 3H). Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) does not exceed total capitalized costs, we are required to write-down capitalized costs to the ceiling. We performed this ceiling test calculation every quarter prior to the sale of the Gas Operations (See Note 3B). No write-downs were required in 2006 or 2005.

See discussion of synthetic fuels asset impairments in "Other Matters – Synthetic Fuels Tax Credits" and in Notes 8 and 9.

Goodwill

As discussed in Note 8, we account for goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), which requires that goodwill be tested for impairment at least annually and more frequently when indicators of impairment exist. For our utility segments, the goodwill impairment tests are performed at the utility operating segment level. We performed the annual goodwill impairment test for both the PEC and PEF segments in the second quarters of 2006 and 2005, each of which indicated no impairment. If the fair values for the utility segments were lower by 5 percent, there still would be no impact on the reported value of their goodwill.

The carrying amounts of goodwill at December 31, 2006 and 2005, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment.

For our former Progress Ventures segment, the goodwill impairment tests were performed at our Georgia Region reporting unit level, which was comprised of four nonregulated generation plants and was one level below the Progress Ventures segment. We performed the annual goodwill impairment test for our Georgia Region reporting unit in the first quarters of 2006 and 2005. The test in 2005 indicated no impairment. In 2006, the test indicated that goodwill was fully impaired, and we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006.

We calculated the fair value of our segments and reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow methodology and published industry valuations and market data as supporting information. These calculations are dependent on subjective factors such as management's estimate of future cash flows, the selection of appropriate discount and growth rates, and assumptions about the timing of when unregulated energy supply and demand would reach market equilibrium. These underlying assumptions and estimates are made as of a point in time; subsequent changes, particularly changes in the discount rates, growth rates or the timing of market equilibrium, could result in a future impairment charge to goodwill.

Synthetic Fuels Tax Credits

Our Coal and Synthetic Fuels business unit owns facilities that produce coal-based solid synthetic fuels as defined under the Internal Revenue Code. The production and sale of the synthetic fuels from these facilities qualifies for tax credits under Section 29/45K if certain requirements are satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the synthetic fuels were produced from a facility placed in service before July 1, 1998. For 2005 and prior years, the amount of Section 29 credits that we were allowed to generate in any calendar year was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized through December 31, 2005, are carried forward indefinitely as deferred alternative minimum tax credits on the Consolidated Balance Sheets. For 2006 and 2007, the Section 29 tax credits have been redesignated as a Section 45K general business credit, which removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision allows us to produce synthetic fuels at a higher level than we have historically produced, should we choose to do so. The current Section 29/45K tax credit program expires at the end of 2007.

In addition, Section 29/45K provides that if the average wellhead price per barrel for unregulated domestic crude oil for the year (the Annual Average Price) exceeds a certain threshold value (the Threshold Price), the amount of tax credits is reduced for that year. Also, if the Annual Average Price increases high enough (the Phase-out Price), the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation. We estimate that the 2006 Annual Average Price will result in an approximate 35 percent phase-out of the synthetic fuels tax credits related to synthetic fuels production in 2006. This estimate is derived from our estimates of the 2006 Threshold Price and Phase-out Price of $55 per barrel and $69 per barrel, respectively, based on an estimated inflation adjustment for 2006. For 2007 synthetic fuels production, the 2007 Annual Average Price is not known until after the end of the year; we will record the 2007 tax credits based on our estimates of what we believe the Annual Average Price will be for 2007. These estimates are based on oil prices in the futures market. Any portion of the tax credits that would be phased out based on the projected 2007 Annual Average Price exceeding the Threshold Price will not be recorded.

We estimate that the 2007 Threshold Price will be approximately $56 per barrel and the Phase-out Price will be approximately $70 per barrel, based on estimated inflation adjustments for 2006 and 2007. The monthly Domestic Crude Oil First Purchases Price published by the Energy Information Agency (EIA) has recently averaged approximately $7 lower than the corresponding daily New York Mercantile Exchange (NYMEX) prompt month settlement price for light sweet crude oil. As of January 31, 2007, the average NYMEX futures price for light sweet crude oil for calendar year 2007 was $59.50 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price, if oil prices for the rest of 2007 remained at the January 31, 2007, average 2007 futures price level of $59.50 per barrel, we currently estimate that the synthetic fuels tax credit amount for 2007 would not be reduced. See further discussion in "Other Matters – Synthetic Fuels Tax Credits."

Pension Costs

As discussed in Note 16A, we maintain qualified noncontributory defined benefit retirement (pension) plans. Our reported costs are dependent on numerous factors resulting from actual plan experience and assumptions of future experience. For example, such costs are impacted by employee demographics, changes made to plan provisions, actual plan asset returns and key actuarial assumptions, such as expected long-term rates of return on plan assets and discount rates used in determining benefit obligations and annual costs.

Due to an increase in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate used to present value future benefit payments, we increased the discount rate to approximately 5.95% at December 31, 2006, from approximately 5.65% at December 31, 2005, which will decrease the 2007 benefit costs recognized, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study by our actuary, which matches our projected benefit payments to a high-quality corporate yield curve. Plan assets performed well in 2006, with returns of approximately 14%. That positive asset performance will result in decreased pension costs in 2007, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2007 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2007 will be $22 million to $30 million, compared with $32 million recognized in 2006.

We have pension plan assets with a fair value of approximately $1.8 billion at December 31, 2006. Our expected rate of return on pension plan assets is 9.0%. We review this rate on a regular basis. Under SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), the expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2005, we elected to lower our expected rate of return from 9.25% to 9.0%. The 9.0% rate of return represents the lower end of our future expected return range given our asset allocation policy. A 0.25% change in the expected rate of return for 2006 would have changed 2006 pension costs by approximately $4 million.

Another factor affecting our pension costs, and sensitivity of the costs to plan asset performance, is the method selected to determine the market-related value of assets, i.e., the asset value to which the 9.0% expected long-term rate of return is applied. SFAS No. 87 specifies that entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. We have historically used a five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension costs sooner under the fair value method than the five-year averaging method, and, therefore, pension costs tend to be more volatile using the fair value method. Approximately 50 percent of our pension plan assets are subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Progress Energy, Inc. is a holding company and, as such, has no revenue-generating operations of its own. Our primary cash needs at the Parent level are our common stock dividend and interest and principal payments on our $2.6 billion of senior unsecured debt. Our ability to meet these needs is dependent on the earnings and cash flows of the Utilities and our nonregulated subsidiaries, and the ability of our subsidiaries to pay dividends or repay funds to us. Our other significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, primarily generated by the Utilities, commercial paper and bank facilities, and our ability to access the long-term debt and equity capital markets for sources of liquidity.

The majority of our operating costs are related to the Utilities. Most of these costs are recovered from ratepayers in accordance with various rate plans. We are allowed to recover certain fuel, purchased power and other costs incurred by PEC and PEF through their respective recovery clauses. The types of costs recovered through clauses vary by jurisdiction. Fuel price volatility can lead to over- or under-recovery of fuel costs, as changes in fuel prices are not immediately reflected in fuel surcharges due to regulatory lag in setting the surcharges. As a result, fuel price volatility can be both a source of and a use of liquidity resources, depending on what phase of the cycle of price volatility we are experiencing. Changes in the Utilities' fuel and purchased power costs may affect the timing of cash flows, but not materially affect net income.

Prior to February 8, 2006, we were a registered holding company under PUHCA 1935, and therefore we obtained approval from the Securities and Exchange Commission (SEC) for the issuance and sale of securities as well as the establishment of intercompany extensions of credit (utility and nonutility money pools). PEC and PEF participate in the utility money pool, which allows the two utilities to lend to and borrow from each other. A nonutility money pool allows our nonregulated operations to lend to and borrow from each other. The Parent can lend money to the utility and nonutility money pools but cannot borrow funds. The Energy Policy Act of 2005 (EPACT) repealed PUHCA 1935 effective February 8, 2006, and transferred to the FERC certain new responsibilities with respect to the regulation of utility holding companies under the Public Utilities Holding Company Act of 2005 (PUHCA 2005). Pursuant to PUHCA 2005, utility holding companies are allowed to continue to engage in financings authorized by the SEC, provided the authorization orders have been filed with the FERC and the holding company continues to comply with such orders, terms and conditions. We have filed all such SEC orders with the FERC; therefore, we are permitted to continue all such financing transactions.

Cash from operations, asset sales, short-term and long-term debt and limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans are expected to fund capital expenditures and common stock dividends for 2007. For the fiscal year 2007, we expect to realize an aggregate amount of approximately $50 million from the sale of stock through these plans.

We believe our internal and external liquidity resources will be sufficient to fund our current business plans. Risk factors associated with credit facilities and credit ratings are discussed below.

The following discussion of our liquidity and capital resources is on a consolidated basis.

Historical for 2006 as Compared to 2005 and 2005 as Compared to 2004

CASH FLOWS FROM OPERATIONS

Cash from operations is the primary source used to meet operating requirements and capital expenditures. Net cash provided by operating activities from continuing operations for the three years ended December 31, 2006, 2005 and 2004, was $1.912 billion, $1.175 billion, and $1.409 billion, respectively.

Cash from operating activities for 2006 increased when compared with 2005. The $737 million increase in operating cash flow was primarily due to a $713 million increase in the recovery of fuel costs at the Utilities, a $201 million increase from the change in accounts receivable, approximately $103 million of proceeds received from the restructuring of a long-term coal supply contract, and $72 million related to recovery of storm restoration costs at PEF. These impacts were partially offset by a $122 million net increase in tax payments in 2006 compared to 2005, $141 million related to a wholesale customer prepayment in 2005 at PEC, as discussed below, and a $57 million decrease from the change in accounts payable. The $201 million change in accounts receivable included $147 million at PEC, principally driven by the timing of wholesale sales, and approximately $47 million at PEF, primarily related to timing of receipts

In 2006 and 2005, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. In 2005, PEF also received approval from the Florida Public Service Commission (FPSC) authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" and Note 7 for additional information.

Cash from operating activities for 2005 decreased when compared with 2004. The $234 million decrease in operating cash flow was primarily due to a $298 million decrease in the recovery of fuel costs at the Utilities, driven by rising fuel costs, and increased working capital needs of $144 million, partially offset by a $193 million reduction in storm cost spending at PEF in 2005 compared to 2004. Cash from operating activities for 2005 also includes a $141 million prepayment received from a wholesale customer. In November 2005, PEC entered into a contract with the Public Works Commission of the City of Fayetteville, North Carolina (PWC), in which the PWC prepaid $141 million in exchange for future capacity and energy power sales. The prepayment is expected to cover approximately two years of electricity service and includes a prepayment discount of approximately $16 million. In 2005, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries. PEF also received approval from the FPSC authorizing PEF to recover $245 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004. See "Future Liquidity and Capital Resources" and Note 7 for additional information.

The increase in working capital needs for 2005 compared to 2004 was mainly driven by a $170 million increase in the change in receivables, a $97 million increase in prepayments and other current assets, and a $52 million increase in inventory purchases, primarily coal at PEC. These impacts were partially offset by a $133 million increase in the change in accounts payable and the current portion of the prepayment received from the PWC as discussed above. The increase in the change in receivables is primarily due to increased sales at the Utilities driven by weather, rising fuel costs and timing of receipts, and increased sales at our nonregulated subsidiaries, mainly driven by changes in the production level of our synthetic fuels facilities over the prior year. The change in accounts payable is primarily due to higher fuel prices at PEF and increased quantities of coal purchases at our nonregulated subsidiaries.

INVESTING ACTIVITIES

Net cash provided (used) by investing activities for the three years ended December 31, 2006, 2005 and 2004, was $271 million, $(914) million and $(649) million, respectively. Excluding proceeds from sales of discontinued operations and other assets of $1.654 billion in 2006 and $475 million in 2005, cash used in investing activities decreased slightly in 2006 when compared with 2005. The decrease in 2006 was primarily due to a $319 million increase in net proceeds from available-for-sale securities and other investments, a $12 million decrease in nuclear fuel additions, and a $14 million decrease in other investing activities, largely offset by a $343 million increase in capital expenditures for utility property. At PEC, the increase in utility property was primarily due to environmental compliance and mobile meter reading project expenditures. At PEF, the increase in utility property was primarily due to repowering the Bartow plant to more efficient natural gas-burning technology; various distribution, transmission and steam production projects; and higher spending at the Hines Unit 4 facility, partially offset by lower spending at the Hines Unit 3 facility. Available-for-sale securities and other investments include marketable debt and equity securities and investments held in nuclear decommissioning and benefit investment trusts.

Utility property additions, including nuclear fuel, for our regulated electric operations were $1.537 billion and $1.206 billion in 2006 and 2005, respectively, or approximately 100 percent of consolidated capital expenditures in both 2006 and 2005. Capital expenditures for our regulated electric operations are primarily for capacity expansion and normal construction activity and ongoing capital expenditures related to environmental compliance programs.

During 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included approximately $1.1 billion from the sale of Gas (See Note 3B), $405 million from the sale of DeSoto and Rowan (See Note 3C), approximately $70 million from the sale of PT LLC (See Note 3D), approximately $27 million from the sale of certain net assets of the coal mining business (See Note 3F), and approximately $16 million from the sale of Dixie Fuels (See Note 3E).

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested, cash used in investing activities increased approximately $368 million in 2005 when compared with 2004 The increase is due primarily to a $254 million decrease in net proceeds from available-for-sale securities and other investments and a $107 million increase in capital expenditures for utility property and nuclear fuel additions. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning and benefit investment trusts

During 2005, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included $405 million in base proceeds from the sale of Progress Rail in March 2005 and $42 million in proceeds from the sale of Winter Park distribution assets in June 2005 (See Notes 3G and 7C).

During 2004, proceeds from sales of discontinued operations and other assets, net of cash divested, primarily included proceeds of approximately $251 million related to the sale of natural gas assets in the Forth Worth basin of Texas and proceeds from the sale of Railcar Ltd. assets of approximately $75 million We used the proceeds from these sales to reduce indebtedness, including $241 million to pay off a PVI bank facility.

FINANCING ACTIVITIES

Net cash (used) provided by financing activities for the three years ended December 31, 2006, 2005 and 2004, was $(2.468) billion, $229 million and $(485) million, respectively. See Note 12 for details of debt and credit facilities.

For 2006, proceeds from sales of discontinued operations and other assets, net of cash divested, were used to reduce holding company debt by $1.7 billion. The increase in cash used in financing activities was primarily related to the retirement of long-term debt in the current year, as discussed below, and a decrease in the proceeds from issuances of long-term debt For 2005, cash provided by financing activities increased primarily due to additional issuances of long-term debt at the Utilities and an increase in common stock issuances For 2004, cash from operations exceeded net cash used in investing activities by $760 million due primarily to asset sales, which allowed for a net decrease in cash requirements provided by financing activities

In addition to the financing activities discussed under "Overview," our financing activities included

2006

- On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010. These senior notes are unsecured Interest on the Floating Rate Senior Notes is based on three-month London Inter Bank Offering Rate (LIBOR) plus 45 basis points and resets quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of proceeds as described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.
- Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, we retired $800 million of our 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.
- On March 31, 2006, Progress Energy, as a well-known seasoned issuer, filed a shelf registration statement with the SEC. The registration statement became effective upon filing with the SEC and will allow Progress Energy to issue an indeterminate number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2006, Progress Energy had the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities
- On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year revolving credit agreement (RCA) with a syndication of financial institutions. The new RCA is scheduled to expire on May 3, 2011, and replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006. The new RCA will continue to be used to provide liquidity support for Progress Energy's issuances of commercial paper and other short-term obligations. The new RCA includes a defined maximum total debt to capital ratio of 68 percent and contains various

cross-default and other acceleration provisions. The new RCA does not include a material adverse change representation for borrowings or a financial covenant for interest coverage. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's and BBB- by S&P.

- On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P. The amended PEC RCA is scheduled to expire on June 28, 2010.
- On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB- by S&P. The amended PEF RCA is scheduled to expire on March 28, 2010.
- On July 3, 2006, PEF paid at maturity $45 million of its 6.77% Medium-Term Notes, Series B with available cash on hand.
- On November 1, 2006, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity $60 million of its 7.17% Medium-Term Notes with available cash on hand.
- On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million, plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand, and no additional debt was incurred in connection with the redemptions. See Note 20 for a discussion of losses on debt redemptions.
- Progress Energy issued approximately 4.2 million shares of common stock resulting in approximately $185 million in proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 1.6 million shares for proceeds of approximately $70 million to meet the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan. For 2006, the dividends paid on common stock were approximately $607 million.

2005

- On January 31, 2005, Progress Energy entered into a new $600 million RCA, which was subsequently terminated on May 16, 2005. In March 2005, Progress Energy's $1.1 billion five-year credit facility was amended to increase the maximum total debt to total capital ratio from 65 percent to 68 percent. In addition to the ongoing RCAs, Progress Energy entered into a new $800 million 364-day credit agreement on November 21, 2005, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, the $800 million of 6.75% Senior Notes was retired, thus effectively terminating the 364-day credit agreement.
- PEC issued $300 million of First Mortgage Bonds, 5.15% Series due 2015; $200 million of First Mortgage Bonds, 5.70% Series due 2035; and $400 million of First Mortgage Bonds, 5.25% Series due 2015. PEC paid at maturity $300 million in 7.50% Senior Notes. PEC also entered into a new $450 million five-year RCA with a syndication of financial institutions, which is scheduled to expire on June 28, 2010, and filed a shelf registration statement with the SEC to provide $1.0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEC to issue various securities, including First Mortgage Bonds, Senior Notes, Debt Securities and Preferred Stock.
- PEF issued $300 million in Mortgage Bonds, 4.50% Series due 2010 and $450 million in Series A Floating Rate Senior Notes due 2008. PEF paid at maturity $45 million in 6.72% Medium-Term Notes, Series B. PEF also entered into a new $450 million five-year RCA with a syndication of financial institutions, which

is scheduled to expire on March 28, 2010, and filed a shelf registration statement with the SEC to provide $1 0 billion of capacity, which was declared effective on December 23, 2005. The shelf registration allows PEF to issue various securities, including First Mortgage Bonds, Debt Securities and Preferred Stock.

- Progress Energy issued approximately 4.8 million shares of our common stock for approximately $208 million in net proceeds from its Investor Plus Stock Purchase Plan and its employee benefit and stock option plans. Included in these amounts were approximately 4.6 million shares for proceeds of approximately $199 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2005, the dividends paid on common stock were approximately $582 million.

2004

- Progress Energy paid at maturity $500 million in 6.55% Senior Notes and entered into a new $1.1 billion five-year line of credit, expiring August 5, 2009. This facility replaced Progress Energy's $250 million 364-day line of credit and its three-year $450 million line of credit, which were both scheduled to expire in November 2004. Proceeds from the sale of natural gas assets were used to extinguish PVI's $241 million bank facility, and Progress Capital Holdings, Inc. paid at maturity $25 million of 6.48% medium-term notes.
- PEC redeemed $35 million of Darlington County 6.6% Series Pollution Control Bonds, $2 million of New Hanover County 6.3% Series Pollution Control Bonds, and $2 million of Chatham County 6 3% Series Pollution Control Bonds. PEC paid at maturity $150 million of 5.875% First Mortgage Bonds and $150 million of 7.875% First Mortgage Bonds. PEC extended to July 27, 2005, its $165 million 364-day line of credit, which was scheduled to expire on July 29, 2004.
- PEF paid at maturity $40 million in 6.69% Medium-Term Notes, Series B.
- Progress Energy issued approximately 1.7 million shares of our common stock for approximately $73 million in net proceeds from our Investor Plus Stock Purchase Plan and our employee benefit and stock option plans. Included in these amounts were approximately 1.4 million shares for proceeds of approximately $62 million to meet the requirements of the 401(k) and the Investor Plus Stock Purchase Plan. For 2004, the dividends paid on common stock were approximately $558 million

Future Liquidity and Capital Resources

Please review the "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein

The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2006 and 2005. It is expected that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our synthetic fuels operations do not currently produce positive operating cash flow due to the difference in timing of when tax credits are recognized for financial reporting purposes and when tax credits are realized for tax purposes (See "Other Matters – Synthetic Fuels Tax Credits").

Cash from operations plus availability under our credit facilities and shelf registration statements is expected to be sufficient to meet our requirements in the near term. To the extent necessary, we may also use limited ongoing equity sales from our Investor Plus Stock Purchase Plan and employee benefit and stock option plans to meet our liquidity requirements.

Over the long term, meeting the anticipated load growth at the Utilities will require a balanced approach, including energy conservation and efficiency programs, development and deployment of new energy technologies, and new generation, transmission and distribution facilities, potentially including new baseload generation facilities in both Florida and the Carolinas by the middle of the next decade. This approach will require the Utilities to make significant capital investments. See "Introduction – Strategy – Regulated Utilities" for additional information. These anticipated capital investments are expected to be funded through a combination of long-term debt, preferred stock and common equity, which is dependent on our ability to successfully access capital markets. We may pursue joint ventures or similar arrangements with third parties in order to share some of the financing and operational risks associated with new baseload generation.

The amount and timing of future sales of company securities will depend on market conditions, operating cash flow, asset sales and our specific needs. We may from time to time sell securities beyond the amount immediately needed to meet capital requirements in order to allow for the early redemption of long-term debt, the redemption of preferred stock, the reduction of short-term debt or for other general corporate purposes.

At December 31, 2006, the current portion of our long-term debt was $324 million, which we expect to fund with a combination of cash from operations, proceeds from sales of assets, commercial paper borrowings and long-term debt. See Note 3 for additional information on asset sales.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, as discussed in "Other Matters – Regulatory Environment" and Note 7, and filings for recovery of environmental costs, as discussed in Note 21 and in "Other Matters – Environmental Matters," may impact our future liquidity and financing activities. The impacts of these matters, including the timing of recoveries from ratepayers, can be both a source of and a use of future liquidity resources.

Base Rates

PEC's base rates are subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC). As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities consistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. Subsequent to 2007, PEC's current North Carolina base rates will continue subject to traditional cost-based rate regulation.

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between a specified threshold and specified cap, which will be adjusted annually, and 100 percent of revenues above the specified cap. PEF's retail base revenues did not exceed the specified 2006 threshold, and thus no revenues were subject to revenue sharing. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Additionally, PEF will continue to recover and collect a return on Hines Unit 2 through the fuel clause through late 2007, when it will be transferred into base rates. If PEF's regulatory return on equity (ROE) falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

PEC Fuel Cost Recovery

On June 16, 2006, the SCPSC approved a settlement agreement for an increase in the fuel rate charged to PEC's South Carolina ratepayers for under-recovered fuel costs and to meet future expected fuel costs. The settlement agreement provided for a $23 million, or 4.6 percent, increase in rates, effective July 1, 2006. At December 31, 2006, PEC's South Carolina deferred fuel balance was $29 million, of which $5 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

On September 25, 2006, the NCUC approved a settlement agreement for an increase in the fuel rate charged to PEC's North Carolina ratepayers. The settlement agreement provided for a $177 million, or 6.7 percent, increase in rates effective October 1, 2006. The settlement agreement further provides for rate increases of $50 million in 2007 and $30 million in 2008 and for PEC to collect its existing deferred fuel balance by September 30, 2009. PEC initially sought an increase of $292 million, or 11.0 percent, but agreed to a three-year phase-in of the increase in order to address customer concerns regarding the magnitude of the proposed increase. PEC will be allowed to calculate and collect interest at 6% on the difference between its fuel factor proposed in its original request to the NCUC and the settlement agreement's factor. At December 31, 2006, PEC's North Carolina deferred fuel balance was $281 million, of which $109 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset. The Carolina Utility Customers Association (CUCA) has appealed the NCUC's order on the grounds that the NCUC does not have the statutory authority to establish fuel rates for more than one year. We anticipate filing a motion to dismiss during the first quarter of 2007. We cannot predict the outcome of this matter.

PEF Pass-through Clause Cost Recovery

On November 8, 2006, the FPSC approved PEF's supplemental filing resulting in a $40 million, or 0.7 percent, increase over 2006 rates to cover rising fuel, environmental compliance and energy conservation costs. The new charges were effective January 1, 2007. At December 31, 2006, PEF was over-recovered in fuel and capacity costs by $63 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. A hearing on the matter has been scheduled by the FPSC for April 2, 2007. PEF believes that its coal procurement practices were prudent and that it has sound legal and factual arguments to successfully defend its position. We cannot predict the outcome of this matter.

On February 8, 2007, the FPSC issued an order approving PEF's request for a need determination to uprate Crystal River Unit No. 3 Nuclear Plant (CR3). The uprate will take place in two stages in 2009 and 2011 and is estimated to cost approximately $382 million, which includes potential transmission system improvements and modifications to comply with environmental regulations. The FPSC has scheduled a hearing on May 23, 2007, to determine whether the uprate costs should be recovered through the fuel adjustment clause. If PEF does not receive approval to recover the uprate costs through the fuel adjustment clause, these costs will be recoverable through base rates, similar to other utility plant additions. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. We cannot predict the outcome of this matter.

PEF has received approval from the FPSC for recovery of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC), which were estimated to be $43 million at December 31, 2006. Additionally, on November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR through the ECRC. The FPSC also approved cost recovery of prudently incurred costs necessary to achieve this strategy, which are currently estimated to be $900 million to $1.7 billion.

Storm Cost Recovery

In 2005, the FPSC issued orders authorizing PEF to recover over a two-year period, including interest, costs it incurred and previously deferred related to PEF's restoration of power to customers associated with the four hurricanes in 2004, including $232 million beginning August 1, 2005, and an additional $13 million, beginning January 1, 2006.

On August 29, 2006, the FPSC approved a settlement agreement related to PEF's storm cost-recovery docket that would allow PEF to extend its current two-year storm surcharge for an additional 12-month period to replenish its storm reserve. The requested extension, which begins in August 2007, will replenish the existing storm reserve by an estimated additional $130 million. In the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. Intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent. The FPSC has the right to review PEF's storm costs for prudence.

Nuclear Cost Recovery

In response to legislation passed by the Florida Legislature in 2006, the FPSC has promulgated rules that will allow PEF to recover prudently incurred siting, preconstruction costs and allowance for funds used during construction (AFUDC) on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. The FPSC approved the new rules on February 13, 2007.

Other Matters

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex. The estimated total in-service cost of Hines Unit 4 approved as part of the Determination of Need was $286 million. The unit is planned for commercial operation in December 2007. If the actual cost is less than the original estimate, ratepayers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent, among other things, extraordinary circumstances as found by the FPSC in subsequent proceedings. The current estimate of in-service cost exceeds the initial project estimate by approximately 12 percent to 15 percent due to what we believe to be extraordinary circumstances. Therefore, we believe that disallowance of these costs by the FPSC in subsequent proceedings is not probable. We cannot predict the outcome of this matter

CAPITAL EXPENDITURES

Total cash from operations provided the funding for our capital expenditures, including property additions, nuclear fuel expenditures and diversified business property additions during 2006.

As shown in the table below, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of internally generated funds, long-term debt, preferred stock and/or common equity. In addition, we have $2.030 billion in credit facilities that support the issuance of commercial paper. Access to the commercial paper market provides additional liquidity to help meet working capital requirements. We anticipate our regulated capital expenditures will increase in 2007 and 2008, primarily due to increased spending on environmental initiatives and current growth and maintenance projects. AFUDC represents the costs of capital funds necessary to finance the construction of new regulated assets.

	Actual	Forecasted		
(in millions)	**2006**	2007	2008	2009
Regulated capital expenditures	**$1,423**	$2,250	$2,380	$2,180
Nuclear fuel expenditures	**114**	180	170	210
AFUDC – borrowed funds	**(7)**	(20)	(40)	(40)
Nonregulated capital and other expenditures	**17**	20	10	10
Total	**$1,547**	$2,430	$2,520	$2,360

Regulated capital expenditures for 2007, 2008 and 2009 in the table above include approximately $640 million, $610 million and $220 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2007, 2008 and 2009 include $320 million, $220 million and $50 million, respectively, at PEC and $320 million, $390 million and $170 million, respectively, at PEF. We currently estimate that total future capital expenditures for the Utilities to comply with current environmental laws and regulations addressing air and water quality, which are eligible for regulatory recovery through either base rates or cost-recovery clauses, could be in excess of $1.0 billion each at PEC and PEF through 2018, which is the latest compliance target date for current air and water quality regulations. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

All projected capital and investment expenditures are subject to periodic review and revision and may vary significantly depending on a number of factors including, but not limited to, industry restructuring, regulatory constraints, market volatility and economic trends.

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2006, we had no outstanding borrowings under our credit facilities. The following table summarizes our RCAs and available capacity at December 31, 2006:

(in millions)	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc.				
Five-year (expiring 5/3/11)	$1,130	$–	$(60)	$1,070
PEC				
Five-year (expiring 6/28/10)	450	–	–	450
PEF				
Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities	$2,030	$–	$(60)	$1,970

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2006, Progress Energy, Inc. had a total amount of $60 million of letters of credit issued, which were supported by the RCA.

All of the revolving credit facilities supporting the credit were arranged through a syndication of financial institutions. There are no bilateral contracts associated with these facilities. See Note 12 for additional discussion of our credit facilities.

Our internal financial policy precludes issuing commercial paper in excess of the supporting lines of credit. At December 31, 2006, we had no outstanding commercial paper and a total of $60 million reserved for letters of credit issued, leaving an additional $1.970 billion available for future borrowing under our credit lines. In addition, we have requirements to pay minimal annual commitment fees to maintain our credit facilities. We expect to continue to use commercial paper issuances as a source of liquidity as long as we maintain our current short-term ratings.

All of the credit facilities include a defined maximum total debt-to-total capital ratio (leverage). We are currently in compliance with these covenants and were in compliance with these covenants at December 31, 2006. See Note 12 for a discussion of the credit facilities' financial covenants. At December 31, 2006, the calculated ratios, pursuant to the terms of the agreements, are as disclosed in Note 12.

Progress Energy, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which Progress Energy may issue an indeterminate number or amount of various securities, including Senior Debt Securities, Junior Subordinated Debentures, Common Stock, Preferred Stock, Stock Purchase Contracts, Stock Purchase Units, and Trust Preferred Securities and Guarantees. The board of directors has authorized the issuance and sale of up to $1.0 billion aggregate principal amount of various securities off the new shelf registration statement, in addition to $679 million of various securities, which were not sold from our prior shelf registration statement. Accordingly, at December 31, 2006, Progress Energy has the authority to issue and sell up to $1.679 billion aggregate principal amount of various securities.

Both PEC and PEF currently have on file with the SEC a shelf registration statement under which each can issue up to $1.0 billion of various long-term debt securities and preferred stock.

Both PEC and PEF can issue First Mortgage Bonds under their respective First Mortgage Bond indentures. At December 31, 2006, PEC and PEF could issue up to $3.333 billion and $4.330 billion, respectively, based on property additions and $1.627 billion and $175 million, respectively, based upon retirements.

CAPITALIZATION RATIOS

The following table shows our total debt to total capitalization ratios at December 31:

	2006	2005
Common stock equity	47.2%	41.6%
Preferred stock and minority interest	0.6%	0.7%
Total debt	52.2%	57.7%

CREDIT RATING MATTERS

The major credit rating agencies have currently rated our securities as follows:

	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Progress Energy, Inc.			
Outlook	Stable	Positive	Stable
Corporate credit rating	n/a	BBB	n/a
Senior unsecured debt	Baa2	BBB-	BBB
Commercial paper	P-2	A-2	F-2
PEC			
Outlook	Positive	Positive	Stable
Corporate credit rating	Baa1	BBB	n/a
Commercial paper	P-2	A-2	F-1
Senior secured debt	A3	BBB	A
Senior unsecured debt	Baa1	BBB-	A-
Subordinate debt	Baa2	n/a	n/a
Preferred stock	Baa3	BB+	BBB+
PEF			
Outlook	Stable	Positive	Stable
Corporate credit rating	A3	BBB	n/a
Commercial paper	P-2	A-2	F-1
Senior secured debt	A2	BBB	A
Senior unsecured debt	A3	BBB-	A-
Preferred stock	Baa2	BB+	BBB+
FPC Capital I			
Preferred stock[a]	Baa2	BB+	n/a
Progress Capital Holdings, Inc.			
Senior unsecured debt[b]	Baa1	BBB-	n/a

[a] Guaranteed by Progress Energy, Inc. and Florida Progress
[b] Guaranteed by Florida Progress

These ratings reflect the current views of these rating agencies, and no assurances can be given that these ratings will continue for any given period of time. However, we monitor our financial condition as well as market conditions that could ultimately affect our credit ratings.

On November 3, 2006, Fitch upgraded the senior unsecured credit ratings of Progress Energy to BBB from BBB-, PEC to A- from BBB+ and PEF to A- from BBB+. The outlook at each entity was changed to stable. The short-term ratings of PEC and PEF were upgraded to F-1 from F-2. The ratings upgrades were based on our reduced business risk due to non-utility asset sales, the $1.3 billion holding company debt reduction and the successful resolution of the Internal Revenue Service (IRS) audit of the Earthco synthetic fuels facilities (Earthco).

On August 31, 2006, Moody's upgraded Progress Energy's outlook to stable from negative, citing expected holding company debt reduction from asset sale proceeds, successful resolution of the IRS audit of the Earthco synthetic fuels facilities, and lower business risk after divestitures of noncore assets. Moody's also upgraded PEC's outlook to positive from stable, citing PEC's manageable leverage, strong cash flow coverage ratios for its current ratings category, and constructive regulatory environments in North Carolina and South Carolina. PEF's outlook remains stable.

On July 25, 2006, S&P affirmed the corporate credit ratings of BBB at Progress Energy, Inc., PEC and PEF and revised each company's outlook to positive from stable. The outlook revision reflects the progress toward our holding company debt reduction plan and expectations of future financial performance at the BBB+ benchmark levels. S&P also improved Progress Energy's business risk profile to 5 from 6 due to the sales of the DeSoto and Rowan plants and Gas, as well as anticipated cash flow benefits related to the idling of our synthetic fuels facilities.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

Our off-balance sheet arrangements and contractual obligations are described below.

Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties that are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, we have issued $1.489 billion of guarantees for future financial or performance assurance. Included in this amount is $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries issued by the Parent (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates.

The majority of contracts supported by the guarantees contain provisions that trigger guarantee obligations based on downgrade events to below investment grade (below Baa3 or BBB-) by Moody's or S&P for the Parent's senior unsecured debt rating, ratings triggers, monthly netting of exposure and/or payments and offset provisions in the event of a default. At December 31, 2006, the Parent's senior unsecured debt rating was Baa2 by Moody's and BBB- by S&P and no guarantee obligations had been triggered. If the guarantee obligations were triggered, the approximate amount of liquidity requirements to support ongoing operations within a 90-day period, associated with guarantees for Progress Energy's nonregulated portfolio and power supply agreements, was $596 million at December 31, 2006. While we believe that we would be able to meet this obligation with cash or letters of credit, if we cannot, our financial condition, liquidity and results of operations will be materially and adversely impacted.

At December 31, 2006, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

Market Risk and Derivatives

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and "Quantitative and Qualitative Disclosures About Market Risk" for a discussion of market risk and derivatives.

Contractual Obligations

We are party to numerous contracts and arrangements obligating us to make cash payments in future years. These contracts include financial arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services. Amounts in the following table are estimated based upon contractual terms, and actual amounts will likely differ from amounts presented below. Further disclosure regarding our contractual obligations is included in the respective notes to the Consolidated Financial Statements. We take into consideration the future commitments when assessing our liquidity and future financing needs. The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2006, in the respective periods in which they are due:

(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt[a] (See Note 12)	$9,242	$324	$1,277	$1,406	$6,235
Interest payments on long-term debt and interest rate derivatives[b]	6,224	545	964	822	3,893
Capital lease obligations (See Note 22B)	589	29	71	68	421
Operating leases (See Note 22B)	428	79	118	59	172
Fuel and purchased power[c][d] (See Note 22A)	13,133	2,613	3,447	1,657	5,416
Other purchase obligations[d] (See Note 22A)	892	479	299	40	74
Minimum pension funding requirements[e]	237	56	95	86	–
Other commitments[f][g]	176	43	26	27	80
Total	$30,921	$4,168	$6,297	$4,165	$16,291

(a) Our maturing debt obligations are generally expected to be repaid with asset sales and cash from operations or refinanced with new debt issuances in the capital markets
(b) Interest payments on long-term debt and interest rate derivatives are based on the interest rate effective at December 31, 2006, and the LIBOR forward curve at December 31, 2006, respectively
(c) Fuel and purchased power commitments represent the majority of our remaining future commitments after debt obligations. Essentially all of our fuel and purchased power costs are recovered through pass-through clauses in accordance with North Carolina, South Carolina and Florida regulations and therefore do not require separate liquidity support.
(d) We have additional contractual obligations associated with our discontinued CCO operations, which are not reflected in this table. They include fuel and purchased power obligations of $11 million for 2007, $1 million for 2008, $2 million each for 2009 through 2011 and $7 million thereafter. These obligations also include other purchase obligations of $15 million each for 2007 through 2009, $13 million each for 2010 and 2011 and $127 million thereafter. We anticipate transferring the obligations under these contracts to a third party as part of our disposition strategy
(e) Projected pension funding status is based on current actuarial estimates and is subject to future revision
(f) In 2008, PEC must begin transitioning North Carolina jurisdictional amounts currently retained internally to its external decommissioning funds. The transition of $131 million must be complete by December 31, 2017, and at least 10 percent must be transitioned each year.
(g) We have certain future commitments related to four synthetic fuels facilities purchased that provide for contingent payments (royalties) through 2007 (See Note 22D)

OTHER MATTERS

Synthetic Fuels Tax Credits

Historically, we have had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 of the Code (Section 29). The production and sale of these products qualifies for federal income tax credits so long as certain requirements are satisfied, including a requirement that the synthetic fuels differ significantly in chemical composition from the coal used to produce such synthetic fuels and that the fuel was produced from a facility that was placed in service before July 1, 1998. Qualifying synthetic fuels facilities entitle their owners to federal income tax credits based on the barrel of oil equivalent of the synthetic fuels produced and sold by these plants. The tax credits associated with synthetic fuels in a particular year may be phased out if annual average market prices for crude oil exceed certain prices. Synthetic fuels are generally not economical to produce and sell absent the credits. In May 2006, we idled production of synthetic fuels at our synthetic fuels facilities. As discussed below in "Impact of Crude Oil Prices," the decision to idle production was based on the high level of oil prices. Based on significantly reduced oil prices combined with current favorable fuel price projections, we resumed limited production at our synthetic fuels facilities in September and October 2006, which continued through the end of 2006. We produced 3.7 million tons of synthetic fuels during 2006.

TAX CREDITS

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code (Section 45K) effective January 1, 2006. The previous amount of Section 29 tax credits that we were allowed to claim in any calendar year through December 31, 2005, was limited by the amount of our regular federal income tax liability. Section 29 tax credit amounts allowed but not utilized are carried forward indefinitely as deferred alternative minimum tax credits. The redesignation of Section 29 tax credits as a Section 45K general business credit removes the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a 20-year carry forward period. This provision would allow us to produce more synthetic fuels than we have historically produced, should we choose to do so.

Total Section 29/45K credits generated through December 31, 2006 (including those generated by Florida Progress prior to our acquisition), were approximately $1.9 billion, of which $974 million has been used to offset regular federal income tax liability, $847 million is being carried forward as deferred tax credits and $38 million has been reserved due to the estimated phase-out of tax credits due to high oil prices, as described below.

IMPACT OF CRUDE OIL PRICES

Although the Section 29/45K tax credit program is expected to continue through 2007, recent market conditions, world events and catastrophic weather events have increased the volatility and level of oil prices that could limit the amount of those credits or eliminate them entirely for 2007. This possibility is due to a provision of Section 29 that provides that if the Annual Average Price exceeds the Threshold Price, the amount of Section 29/45K tax credits is reduced for that year. Also, if the Annual Average Price exceeds the Phase-out Price, the Section 29/45K tax credits are eliminated for that year. The Threshold Price and the Phase-out Price are adjusted annually for inflation.

If the Annual Average Price falls between the Threshold Price and the Phase-out Price for a year, the amount by which Section 29/45K tax credits are reduced will depend on where the Annual Average Price falls in that continuum. For example, for 2005, the Threshold Price was $53.20 per barrel and the Phase-out Price was $66.78 per barrel. If the Annual Average Price had been $59.99 per barrel, there would have been a 50 percent reduction in the amount of Section 29 tax credits for that year. Based on the Annual Average Price of $50.26, there was no phase-out of our synthetic fuels tax credits in 2005.

The Department of the Treasury calculates the Annual Average Price based on the Domestic Crude Oil First Purchases Prices published by the EIA. Because the EIA publishes its information on a three-month lag, the secretary of the Treasury finalizes the calculations three months after the year in question ends. Thus, the Annual Average Price for calendar year 2006 is expected to be published in early April 2007.

We estimate that the 2006 Threshold Price will be approximately $55 per barrel and the Phase-out Price will be approximately $69 per barrel, based on an estimated inflation adjustment for 2006. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $7 lower than the corresponding daily NYMEX prompt month settlement price for light sweet crude oil. Through December 31, 2006, the average daily NYMEX settlement price for light sweet crude oil was $66.25 per barrel. Based upon the estimated 2006 Threshold Price and Phase-out Price, assuming that the $7 average differential between the Domestic Crude Oil First Purchases Price published by the EIA and the NYMEX settlement price continued through December 31, 2006, we estimate that the synthetic fuels tax credit amount for 2006 will be reduced by approximately 35 percent. Therefore, we reserved 35 percent or approximately $38 million of the $107 million of tax credits generated during 2006. The final calculations of any reductions in the value of the tax credits will not be determined until April 2007 when final 2006 oil prices are published.

We estimate that the 2007 Threshold Price will be approximately $56 per barrel and the Phase-out Price will be approximately $70 per barrel, based on an estimated inflation adjustment for 2006 and 2007. The monthly Domestic Crude Oil First Purchases Price published by the EIA has recently averaged approximately $7 lower than the corresponding daily NYMEX prompt month settlement price for light sweet crude oil. As of January 31, 2007, the average NYMEX futures price for light sweet crude oil for calendar year 2007 was $59.50 per barrel. Based upon the estimated 2007 Threshold Price and Phase-out Price, if oil prices for the rest of 2007 remained at the January 31, 2007, average 2007 futures price level of $59.50 per barrel, we currently estimate that the synthetic fuels tax credit amount for 2007 would not be reduced.

In January 2007 we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices. These contracts will provide protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production and will be marked-to-market with changes in fair value recorded through earnings. Our synthetic fuels production levels for 2007 remain uncertain because we cannot predict with any certainty the Annual Average Price of oil for 2007. We will continue to monitor the environment surrounding synthetic fuels production and will adjust our production as warranted by changing conditions. See Note 17 and "Quantitative and Qualitative Disclosures About Market Risk" for a discussion of market risk and derivatives.

IMPAIRMENT OF SYNTHETIC FUELS AND OTHER RELATED LONG-LIVED ASSETS

We monitor our long-lived assets for impairment as warranted. With the idling of our synthetic fuels facilities during the second quarter of 2006, we performed an impairment evaluation of our synthetic fuels and other related operating long-lived assets. The impairment test considered numerous factors, including, among other things, continued high oil prices and the then-current "idle" state of our synthetic fuels facilities. Based on the results of the impairment test, we recorded pre-tax impairment charges of $91 million ($55 million after-tax) during the quarter ended June 30, 2006 (See Notes 8 and 9). These charges represent the entirety of the asset carrying value of our synthetic fuels intangible assets and manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located.

SALE OF PARTNERSHIP INTEREST

In June 2004, through our subsidiary Progress Fuels, we sold in two transactions a combined 49.8 percent partnership interest in Colona, one of our synthetic fuels facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost-recovery basis as the facility produces and sells synthetic fuels and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectability is reasonably assured. Gain recognition is dependent on the synthetic fuels production qualifying for Section 29/45K tax credits and the value of such tax credits as discussed above. Until the gain recognition criteria are met, gains from selling interests in Colona will be deferred. It is possible that gains will be deferred to subsequent quarters, or to a subsequent calendar year, until there is persuasive evidence that no tax credit phase-out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters in a calendar year or to a subsequent calendar year. In the event that the synthetic fuels tax credits from the Colona facility are reduced, including from an extended idling of our production due to an increase in the price of oil that could limit or eliminate synthetic fuels tax credits, the amount of proceeds realized from the sale could be significantly impacted. At December 31, 2006, a pre-tax gain on monetization of $7 million has been deferred. Based on the current level of oil prices and subject to final adjustments, we expect to recognize this gain in 2007. Beginning with the payment for the second quarter of 2006, the minority interest parties have elected to defer their cash payments in consideration of the idling of the synthetic fuels facilities at that time. In consideration of the resumption of limited synthetic fuels production in the fourth quarter of 2006, the minority interest parties made a partial payment in January 2007.

See Note 22D for additional discussion related to our synthetic fuels operations.

Regulatory Environment

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and other federal and state agencies common to the utility business. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the Utilities are permitted to earn, are subject to the approval of these governmental agencies.

PEC and PEF continue to monitor developments impacting retail competition in their respective service territories. Movement toward deregulation throughout the nation has effectively ceased due to numerous factors including, but not limited to, California's experience with retail deregulation. To our knowledge, there is currently no enacted or proposed legislation in North Carolina, South Carolina or Florida that would give retail customers the right to choose their electricity provider or otherwise restructure or deregulate the electric industry. We cannot anticipate when, or if, any of these states will move to increase retail competition in the electric industry.

The retail rate matters affected by state regulatory authorities are discussed in detail in Notes 7B and 7C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

Issues regarding the timing, creation and structure of transmission organizations are evaluated by the Utilities' regulatory authorities. We cannot predict the outcome of these matters (See Note 7D).

On May 5, 2006, the Florida state legislature passed a comprehensive energy bill, which has been signed by the governor. The legislation creates a new energy council tasked with developing a statewide energy policy, provides incentives to renewable energy sources and fosters the construction of new nuclear power plants, including streamlining the siting of nuclear power plants and related transmission facilities, exempting new nuclear plants from the FPSC bid rule and requiring the FPSC to issue rules authorizing alternative cost-recovery mechanisms for pre-construction costs and construction cost financing. See "Nuclear" below for related FPSC rule issuances. PEF cannot determine at this time how the final rules and regulations resulting from this legislation will impact its operations and financial condition.

Due to the damage electric utility facilities suffered during recent hurricanes, during 2006 the FPSC adopted rules that require Florida's investor-owned electric utilities, including PEF, to strengthen cost effectively, or storm harden, the state's electric infrastructure. Storm-hardening plans are required to be filed and updated every three years for the FPSC's approval. Each plan must address such factors as the effect of extreme wind, flooding and storm surges on electric facilities. The plans must identify critical infrastructure and the respective utilities' deployment strategy for strengthening electric service in their service areas. In addition, state utilities are required to inspect their wooden distribution poles once every eight years. PEF does not believe that compliance with these rules will materially increase PEF's costs due to its pole inspection and vegetation maintenance programs already in effect. Costs to comply with the storm-hardening rules are recoverable through PEF's base rates.

The FPSC has published a proposed rule that specifies what storm costs will be recoverable and whether such recoverable costs would be offset against a utility's storm reserve fund or recoverable through its base rates. The FPSC held a public workshop on February 21, 2007, to discuss the proposed rule with the intent to issue a final rule prior to the 2007 storm season. We cannot predict the outcome of this matter.

On April 26, 2006, PEC submitted a license renewal application with the FERC seeking a 50-year license for its Tillery and Blewett hydroelectric generating plants. The license for these plants currently expires in April 2008 and the requested renewal will allow the plants to continue operations until 2058. PEC and a key group of stakeholders have reached an agreement in principle that supports PEC's relicensing application. The agreement in principle, which has been filed with the FERC, will establish increased water flows from both plants and will protect water supplies for local governments as well as provide enhancements for recreation, water quality and aquatic habits. The remaining phase of the application process will take approximately one year and includes review by the FERC and solicitation of public comment. We cannot predict the outcome of this matter.

In 2004, the FERC issued orders concerning utilities' ability to sell wholesale electricity at market-based rates, including the adoption of two interim screens for assessing an applicant's potential generation market power for determining whether the applicant should be allowed to sell wholesale electricity at market-based rates. The Utilities do not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, PEC filed revisions to its market-based rate tariffs restricting PEC to sales outside of PEC's control area and peninsular Florida, and filed a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs. We do not anticipate that the operations of the Utilities will be materially impacted by these market-based rates decisions.

Legal

We are subject to federal, state and local legislation and court orders. These matters are discussed in detail in Note 22D. This discussion identifies specific issues, the status of the issues, accruals associated with issue resolutions and our associated exposures.

Nuclear

Nuclear generating units are regulated by the NRC. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit or take some combination of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved.

Our nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, repairs and certain other modifications (See Notes 5 and 22D).

Due to the anticipated growth in our service territories, we estimate that we will require new baseload generation facilities in both Florida and the Carolinas by the middle of the next decade, and we are evaluating the best available options for this generation, including advanced design nuclear and clean coal technologies. At this time, no definitive decision has been made.

We have announced that we are pursuing development of combined license (COL) applications. Our announcement is not a commitment to build a nuclear plant. It is a necessary step to keep open the option of building a plant or plants. On January 23, 2006, we announced that PEC selected a site at the Shearon Harris Nuclear Plant (Harris) to evaluate for possible future nuclear expansion.

We currently expect to file the application for the COL for PEC's Harris site in 2007. We have selected for PEC the Westinghouse Electric AP-1000 reactor design as the technology upon which to base the potential application submission. On December 12, 2006, we announced that PEF selected a site in Levy County, Fla., to evaluate for possible future nuclear expansion, and PEF expects to file the application for the COL in 2008. We have not selected the reactor design technology upon which to base the PEF potential application submission. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, construction activities could begin as early as 2010, and new plants could be online in late 2016. The NRC estimates that it will take approximately three to four years to review and process the COL applications.

On January 16, 2007, the U.S. Supreme Court declined to hear an appeal of a Ninth Circuit U.S. Court of Appeals' decision in which the Ninth Circuit held that the NRC is required to consider the environmental impacts of terrorist attacks under the National Environmental Policy Act in authorizing an independent spent fuel storage installation. Similar cases, including cases involving operating license renewals, are pending in seven other jurisdictions. The NRC is considering the scope and import of the Ninth Circuit's decision in reviewing its operating license renewal program. The extent and timing of the NRC's application of the case is unclear at this time, and the impact, if any, on PEC's pending Harris operating license renewal application or any future PEC or PEF operating licensing proceedings cannot be predicted at this time.

A new nuclear plant may be eligible for the federal production tax credits and risk insurance provided by EPACT. EPACT provides an annual tax credit of 1.8 cents per kWh for nuclear facilities for the first eight years of operation. The credit is limited to the first 6,000 MW of new nuclear generation in the United States and has an annual cap of $125 million per 1,000 MW of national MW capacity limitation allocated to the unit. In April 2006, the IRS provided interim guidance that the 6,000 MW of production tax credits generally will be allocated to new nuclear facilities that file license applications with the NRC by December 31, 2008, had poured safety-related concrete prior to January 1, 2014, and were placed in service before January 1, 2021. There is no guarantee that the interim guidance will be incorporated into the final regulations governing the allocation of production tax credits. Multiple utilities have announced plans to pursue new nuclear plants. There is no guarantee that any nuclear plant we construct would qualify for these or other incentives. We cannot predict the outcome of this matter.

In accordance with provisions of Florida's comprehensive energy bill discussed above, in December 2006, the FPSC ordered new rules that would allow investor-owned utilities such as PEF to request partial recovery of the planning and construction costs of a nuclear power plant prior to commercial operation. The FPSC issued a final rule on February 13, 2007, under which utilities will be allowed to recover prudently incurred siting, preconstruction costs and AFUDC on an annual basis through the capacity cost-recovery clause. Such amounts will not be included in a utility's rate base when the plant is placed in commercial operation. In addition, the rule will require the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. Also, on February 1, 2007, the FPSC amended its power plant bid rules to, among other things, exempt nuclear power plants from existing bid requirements.

Environmental Matters

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina or the state of Florida. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each potentially responsible parties (PRPs) at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other potential PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. Hazardous and solid waste management matters are discussed in detail in Note 21.

We accrue costs to the extent our liability is probable and the costs can be reasonably estimated in accordance with accounting principles generally accepted in the United States of America (GAAP). Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates could change and additional losses, which could be material, may be incurred in the future.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which would likely result in increased planned capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require additional reductions in air emissions of nitrogen oxide (NOx), SO_2, carbon dioxide (CO_2) and mercury. Some of these proposals establish nationwide caps and emission rates over an extended period of time. This national multipollutant approach to air pollution control could involve significant capital costs that could be material to our financial position or results of operations. Control equipment that will be installed pursuant to the provisions of the Clean Smokestacks Act, CAIR, CAMR and CAVR, which are discussed below, may address some of the issues outlined above. CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

The following tables contain information about our current estimates of capital expenditures to comply with environmental laws and regulations described below. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Estimated expenditures for the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) include the cost to install NOx controls under North Carolina's and South Carolina's programs to comply with the federal eight-hour ozone standard. The air quality controls installed to comply with the NOx SIP Call and Clean Smokestacks Act will result in a reduction of the costs to meet the CAIR requirements for our North Carolina units at PEC. We review our estimates on an ongoing basis. The timing and extent of the costs for future projects will depend upon final compliance strategies.

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	*Cumulative Spent* through December 31, 2006
NOx SIP Call	2002-2007	$355	$346
Clean Smokestacks Act	2002-2013	1,000-1,400	562
CAIR/CAMR/CAVR	2005-2018	1,100-2,000	28
Total air quality		2,455-3,755	936
Clean Water Act Section 316(b)[a]		–	1
North Carolina Groundwater Standard[b]		–	–
Total water quality		–	1
Total air and water quality		$2,455-$3,755	$937

[a] Compliance plans to meet the requirements of a revised or new implementing rule under Section 316(b) of the Clean Water Act will be determined upon finalization of the rule. See discussion under "Water Quality."
[b] Compliance plans will be determined upon finalization of the changes expected to be proposed to the North Carolina groundwater quality standard for arsenic.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants in an effort to determine whether changes at those facilities were subject to New Source Review (NSR) requirements or New Source Performance Standards under the Clean Air Act. We were asked to provide information to the EPA as part of this initiative and cooperated in supplying the requested information. The outcome of this matter cannot be predicted. However, the EPA has initiated civil enforcement actions against unaffiliated utilities as part of this initiative. Some of these actions resulted in settlement agreements requiring expenditures by these unaffiliated utilities in excess of $1.0 billion. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the companies may seek recovery of the related costs through rate adjustments or similar mechanisms. The U.S. Supreme Court has heard arguments, but not yet issued a ruling, related to an appeal of a decision issued by the U.S. Court of Appeals for the Fourth Circuit, in a case involving an unaffiliated utility, holding that NSR applies to projects that result in an increase in maximum hourly emissions.

On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit set aside the EPA's 2003 NSR equipment replacement rule. The rule would have provided a more uniform definition of routine equipment replacement. The court had earlier set aside a provision in the NSR rule, which had exempted the installation of pollution control projects from review. The Court denied a request by the EPA for a re-hearing regarding this matter on June 30, 2006. These projects are now subject to NSR requirements, adding time and cost to the installation process. On November 27, 2006, the EPA filed a writ of certiorari petition requesting that the U.S. Supreme Court review the U.S. Court of Appeals for the District of Columbia Circuit's ruling that vacated the agency's plant renovation exemption for its NSR rule. The outcome of this matter cannot be predicted.

NOx SIP Call Rule under Section 110 of the Clean Air Act

The NOx SIP Call is an EPA rule that requires 22 states, including North Carolina, South Carolina and Georgia, to further reduce NOx emissions. The NOx SIP Call is not applicable to Florida. Further technical analysis and rulemaking may result in requirements for additional controls at some units. Increased O&M expenses relating to the NOx SIP Call are not expected to be material to our or PEC's results of operations.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,100 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. To meet SO_2 emission targets, PEC is installing devices that neutralize sulfur compounds formed during coal combustion (scrubbers) on some of its coal-fired units. These devices combine the sulfur in gaseous emissions with other chemicals to form inert compounds, such as gypsum, that are then removed. In March 2006, PEC filed its annual estimate with the NCUC of the total capital expenditures to meet emission targets under the Clean Smokestacks Act by the end of 2013, which were approximately $1.1 billion to $1.4 billion at the time of the filing. Currently, the estimate is $1.0 billion to $1.4 billion. The increase in estimated total capital expenditures from the original 2002 estimate of $813 million is primarily due to the higher cost and revised quantities of construction materials, such as concrete and steel, refinement of cost and scope estimates for the current projects, and increases in the estimated inflation factor applied to future project costs. We are continuing to evaluate various design, technology, and new generation options that could further change expenditures required by the Clean Smokestacks Act. O&M expenses will significantly increase due to the additional personnel, materials and general maintenance associated with the equipment. O&M expenses are currently recoverable through base rates.

The Clean Smokestacks Act also freezes the state's utilities' base rates for five years, which ends in 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities consistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the utilities' last general rate case. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. For the years ended December 31, 2006, 2005 and 2004, PEC recognized amortization of $140 million, $147 million and $174 million, respectively, and has recognized $535 million in cumulative amortization through December 31, 2006. The remaining amortization requirement of $34 million will be recorded during the one-year period ending December 31, 2007. The NCUC will hold a hearing prior to December 31, 2007, to determine cost-recovery amounts for 2008 and 2009.

Two of PEC's largest coal-fired generation plants (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. In 2005, PEC entered into an agreement with the joint owner to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B).

Pursuant to the Clean Smokestacks Act, PEC entered into an agreement with the state of North Carolina to transfer to the state certain NOx and SO_2 emissions allowances that result from compliance with the collective NOx and SO_2 emissions limitations set in the Clean Smokestacks Act. The Clean Smokestacks Act also required the state to undertake a study of mercury and CO_2 emissions in North Carolina. The future regulatory interpretation, implementation or impact of the Clean Smokestacks Act cannot be predicted.

Clean Air Interstate Rule, Clean Air Mercury Rule and Clean Air Visibility Rule

On March 10, 2005, the EPA issued the final CAIR. The EPA's rule requires the District of Columbia and 28 states, including North Carolina, South Carolina, Georgia and Florida, to reduce NOx and SO_2 emissions in order to reduce levels of fine particulate matter and impacts to visibility. The CAIR sets emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2.

PEF has joined a coalition of Florida utilities that has filed a challenge to the CAIR as it applies to Florida. A petition for reconsideration and stay and a petition for judicial review of the CAIR were filed on July 11, 2005. On October 27, 2005, the District of Columbia Circuit Court issued an order granting the motion for stay of the proceedings. On December 2, 2005, the EPA announced a reconsideration of four aspects of the CAIR, including its applicability to Florida. On March 16, 2006, the EPA denied all pending reconsiderations, allowing the challenge to proceed. While we consider it unlikely that this challenge would eliminate the compliance requirements of the CAIR, it could potentially reduce or delay our costs to comply with the CAIR. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAIR, which is very similar to the EPA's model rule. PEF and other Florida utilities are participating in an administrative review of the state-adopted rule. The outcome of these matters cannot be predicted.

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that sets emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encourages a cap-and-trade approach to achieving those caps, and a de-listing rule that eliminated any requirement to pursue a maximum achievable control technology approach for limiting mercury emissions from coal-fired power plants. NOx and SO_2 controls also are effective in reducing mercury emissions. However, according to the EPA the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NOx and SO_2 under CAIR. The de-listing rule has been challenged by a number of parties; the resolution of the challenges could impact our final compliance plans and costs. On October 21, 2005, the EPA announced a reconsideration of the CAMR. On May 31, 2006, the EPA issued a determination confirming the de-listing. Sixteen states have subsequently petitioned for a review of this determination. The outcome of this matter cannot be predicted.

States were required to adopt mercury rules implementing the CAMR by November 17, 2006, which are subject to review and approval by the EPA. A number of states, including North Carolina, South Carolina and Florida, did not meet the deadline for submission to the EPA. The EPA has indicated it will defer action. At December 31, 2006, of the three states in which the Utilities operate, all had formally proposed mercury regulations. The North Carolina Environmental Management Commission adopted the proposed rule on November 9, 2006, which is subject to final approval by the North Carolina legislature. North Carolina's rule adopts the EPA's cap-and-trade approach and requires the addition of mercury controls by 2018 on certain of PEC's North Carolina units that do not have scrubbers. PEC will have until 2013 to provide the agency detailed plans for the installation of controls at existing plants. South Carolina's rule, which was proposed on October 27, 2006, adopts the EPA's cap-and-trade approach and requires that 25 percent of the mercury allowances allocated to each unit be held in a compliance supplement set-aside pool. Allowances in the set-aside pool may be used by a unit to meet compliance requirements but cannot be traded. South Carolina's rule was adopted on January 11, 2007, and is subject to final approval by the South Carolina legislature. On June 29, 2006, the Florida Environmental Regulation Commission adopted the Florida CAMR. The Florida rule adopts the EPA's cap-and-trade approach with changes to the EPA's mercury allowance allocations in the rule's first phase. The outcome of this matter cannot be predicted.

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. Depending on the approach taken by the states, the reductions associated with BART would begin in 2014. CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of CAIR may be used by states as a BART substitute. Plans for compliance with CAIR and CAMR may fulfill BART obligations, but the states could require the installation of additional air quality controls if they do not achieve reasonable progress in improving visibility. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, Bartow Unit No. 3, and Crystal River Units No. 1 and No. 2. The outcome of this matter cannot be predicted. On December 12, 2006, the U.S. Court of Appeals for the District of Columbia Circuit decided in favor of the EPA in a case brought by the National Parks Conservation Association that alleges the EPA acted improperly by substituting the requirements of CAIR for BART for NOx and SO_2 from electric generating units in areas covered by CAIR.

PEC and PEF are each developing an integrated compliance strategy to meet all the requirements of the CAIR, CAMR and CAVR. We are evaluating various design, technology, and new generation options that could change PEC's and PEF's costs to meet the requirements of CAIR, CAMR and CAVR.

On October 14, 2005, the FPSC approved PEF's petition for the recovery of costs associated with the development and implementation of an integrated strategy to comply with the CAIR, CAMR and CAVR through the ECRC. On March 31, 2006, PEF filed a series of compliance alternatives with the FPSC to meet these federal environmental rules. At the time, PEF's recommended proposed compliance plan included approximately $740 million of estimated capital costs expected to be spent through 2016, to plan, design, build and install pollution control equipment at our Anclote and Crystal River plants. On October 27, 2006, PEF filed supplemental testimony to inform the FPSC that estimated capital costs for the series of compliance alternatives are likely to increase by approximately 25 percent to 30 percent from the estimates filed in March 2006, primarily due to the higher cost of labor and construction materials, such as concrete and steel, and refinement of cost and scope estimates for the current projects. These costs will continue to change depending upon the results of the engineering and strategy development work and/or increases in the underlying material, labor and equipment costs. Subsequent rule interpretations, equipment availability, or the unexpected acceleration of the initial NOx or other compliance dates, among other things, could require acceleration of some projects. On November 6, 2006, the FPSC approved PEF's petition for its integrated strategy to address compliance with CAIR, CAMR and CAVR. They also approved cost recovery of prudently incurred costs necessary to achieve this strategy.

North Carolina Attorney General Petition under Section 126 of the Clean Air Act

In March 2004, the North Carolina attorney general filed a petition with the EPA, under Section 126 of the Clean Air Act, asking the federal government to force coal-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet national air quality standards for ozone and particulate matter. On March 16, 2006, the EPA issued a final response denying the petition. The EPA's rationale for denial is that compliance with CAIR will reduce the emissions from surrounding states sufficiently to address North Carolina's concerns. On June 26, 2006, the North Carolina attorney general filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking a review of the agency's final action on the petition. The outcome of this matter cannot be predicted.

National Ambient Air Quality Standards

On December 21, 2005, the EPA announced proposed changes to the National Ambient Air Quality Standards (NAAQS) for particulate matter. The EPA proposed to lower the 24-hour standard for particulate matter less than 2.5 microns in diameter (PM 2.5) from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In addition, the EPA proposed to establish a new 24-hour standard of 70 micrograms per cubic meter for particulate matter that is between 2.5 and 10 microns in diameter (PM 2.5-10). The EPA also proposed to eliminate the current standards for particulate matter less than 10 microns in diameter (PM 10). On September 20, 2006, the EPA announced that it is finalizing the PM 2.5 NAAQS as proposed. In addition, the EPA decided not to establish a PM 2.5-10 NAAQS, and it is eliminating the annual PM 10 NAAQS, but the EPA is retaining the 24-hour PM 10 NAAQS. These changes are not expected to result in designation of any additional nonattainment areas in PEC's or PEF's service territories On December 18, 2006, environmental groups and 13 states filed a joint petition with the U S Circuit Court of Appeals for the District of Columbia Circuit arguing that the EPA's new particulate matter rule does not adequately restrict levels of particulate matter. The outcome of this matter cannot be predicted.

Water Quality

1. General

As a result of the operation of certain control equipment needed to address the air quality issues outlined above, new wastewater streams may be generated at the affected facilities. Integration of these new wastewater streams into the existing wastewater treatment processes may result in permitting, construction and treatment requirements imposed on the Utilities in the immediate and extended future. The outcome of this matter cannot be predicted.

2. Section 316(b) of the Clean Water Act

Section 316(b) of the Clean Water Act (Section 316(b)) requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The EPA promulgated a rule implementing Section 316(b) in respect to existing power plants in July 2004. The July 2004 rule required assessment of the baseline environmental effect of withdrawal of cooling water and development of technologies and measures for reducing environmental effects by certain percentages. Additionally, the rule authorized establishment of alternative performance standards where the site-specific costs of achieving the otherwise applicable standards would have been substantially greater than either the benefits achieved or the costs considered by the EPA during the rulemaking.

Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many important provisions of the rule to the EPA. As a result of that decision, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule once it is established by the EPA. Costs of compliance with a new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our most recent cost estimates to comply with the July 2004 implementing rule were $60 million to $90 million, including $5 million to $10 million at PEC and $55 million to $80 million at PEF. The outcome of this matter cannot be predicted.

3. North Carolina Groundwater Standard

On September 14, 2006, the North Carolina Division of Water Quality (NCDWQ) appeared before the North Carolina Environmental Management Commission and recommended the state's groundwater quality standard for arsenic be revised to 0.00002 milligrams/liter. The existing groundwater quality standard for arsenic is 0.05 milligrams/liter. The North Carolina Environmental Management Commission granted approval for NCDWQ staff to publish a notice in the North Carolina Register and schedule public hearings. The rulemaking process will require at least six months before the standard may be changed. Trace amounts of arsenic are commonly present in coal fly ash sluice water, coal pile runoff, flue gas desulphurization byproducts, and other coal combustion byproducts. The specific requirements of the rule as finally adopted and associated costs, if any, cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other greenhouse gases. The treaty went into effect on February 16, 2005. The United States has not adopted the Kyoto Protocol, and the Bush administration favors voluntary programs. There are proposals and ongoing studies at the state and federal levels to address global climate change that would regulate CO_2 and other greenhouse gases. Reductions in CO_2 emissions to the levels specified by the Kyoto Protocol and some additional proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from ratepayers. The cost impact of legislation or regulation to address global climate change would depend on the specific legislation or regulation enacted and cannot be determined at this time. We have articulated principles that we believe should be incorporated into any global climate change policy. While the outcome of this matter cannot be predicted, we are taking voluntary action on this important issue as part of our commitment to environmental stewardship and responsible corporate citizenship.

In a decision issued July 15, 2005, the U.S. Court of Appeals for the District of Columbia Circuit denied petitions for review filed by several states, cities and organizations seeking the regulation by the EPA of CO_2 emissions from new automobiles under the Clean Air Act, holding that the EPA administrator properly exercised his discretion in denying the request for regulation Following denial of a request for rehearing, the petitioners filed a petition for *writ of certiorari* with the U S Supreme Court, seeking a review of the decision. On June 26, 2006, the U S Supreme Court agreed to review the decision Oral argument was held on November 29, 2006. The outcome of this matter cannot be predicted.

In 2005, we initiated a study to assess the impact of constraints on CO_2 and other air emissions and on March 27, 2006, we issued our report to shareholders for an assessment of global climate change and air quality risks and actions. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the Clean Smokestacks Act.

New Accounting Standards

See Note 2 for a discussion of the impact of new accounting standards.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions. Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We mitigate such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties (See Note 17).

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review the "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

Certain market risks are inherent in our financial instruments, which arise from transactions entered into in the normal course of business. Our primary exposures are changes in interest rates with respect to our long-term debt and commercial paper, fluctuations in the return on marketable securities with respect to our nuclear decommissioning trust funds, changes in the market value of CVOs, and changes in energy-related commodity prices.

These financial instruments are held for purposes other than trading. The risks discussed below do not include the price risks associated with nonfinancial instrument transactions and positions associated with our operations, such as purchase and sales commitments and inventory.

Interest Rate Risk

From time to time, we use interest rate derivative instruments to adjust the mix between fixed and floating rate debt in our debt portfolio, to mitigate our exposure to interest rate fluctuations associated with certain debt instruments, and to hedge interest rates with regard to future fixed-rate debt issuances.

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in the transaction is the cost of replacing the agreements at current market rates. We enter into interest rate derivative agreements only with banks with credit ratings of single A or better.

We use a number of models and methods to determine interest rate risk exposure and fair value of derivative positions. For reporting purposes, fair values and exposures of derivative positions are determined at the end of the reporting period using the Bloomberg Financial Markets system.

In accordance with SFAS No. 133, "Accounting for Derivatives and Hedging Activities" (SFAS No. 133), interest rate derivatives that qualify as hedges are separated into one of two categories: cash flow hedges or fair value hedges. Cash flow hedges are used to reduce exposure to changes in cash flow due to fluctuating interest rates. Fair value hedges are used to reduce exposure to changes in fair value due to interest rate changes.

The following tables provide information at December 31, 2006 and 2005, about our interest rate risk-sensitive instruments. The tables present principal cash flows and weighted-average interest rates by expected maturity dates for the fixed and variable rate long-term debt and Florida Progress-obligated mandatorily redeemable securities of trust. The tables also include estimates of the fair value of our interest rate risk-sensitive instruments based on quoted market prices for these or similar issues. For interest rate swaps and interest rate forward contracts, the tables present notional amounts and weighted-average interest rates by contractual maturity dates for 2007 to 2011 and thereafter and the fair value of the related hedges. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest rate swaps and the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

(dollars in millions) December 31, 2006	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value December 31, 2006
Fixed-rate long-term debt	$324	$427	$400	$306	$1,000	$5,065	$7,522	$7,820
Average interest rate	6.79%	6.67%	5.95%	4.53%	6.96%	6.13%	6.23%	
Variable-rate long-term debt	–	$450	–	$100	–	$861	$1,411	$1,411
Average interest rate	–	5.77%	–	5.82%	–	3.62%	4.47%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed	–	–	–	–	$(50)	–	$(50)	$(1)
Average pay rate	–	–	–	–	(b)	–	(b)	
Average receive rate	–	–	–	–	4.65%	–	4.65%	
Interest rate forward contracts[c]	$100	–	–	–	–	–	$100	$(2)
Average pay rate	5.61%	–	–	–	–	–	5.61%	
Average receive rate	(b)	–	–	–	–	–	(b)	

(a) FPC Capital I – Quarterly Income Preferred Securities
(b) Rate is 3-month LIBOR, which was 5.36% at December 31, 2006
(c) Anticipated 10-year debt issue hedges mature on October 1, 2017, and require mandatory cash settlement on October 1, 2007

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

(dollars in millions) December 31, 2005	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value December 31, 2005
Fixed-rate long-term debt[a]	$513	$674	$827	$401	$306	$6,611	$9,332	$9,768
Average interest rate	6.79%	6.41%	6.27%	5.95%	4.53%	6.34%	6.29%	
Variable-rate long-term debt	–	–	$450	–	$100	$861	$1,411	$1,411
Average interest rate	–	–	4.88%	–	5.03%	3.05%	3.77%	
Debt to affiliated trust[b]	–	–	–	–	–	$309	$309	$312
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate derivatives								
Pay variable/receive fixed	–	–	$(100)	–	–	$(50)	$(150)	$(2)
Average pay rate	–	–	(c)	–	–	(c)	(c)	
Average receive rate	–	–	4.10%	–	–	4.65%	4.28%	
Interest rate forward contracts[d]	$100	–	–	–	–	–	$100	$1
Average pay rate	4.87%	–	–	–	–	–	4.87%	
Average receive rate	(c)	–	–	–	–	–	(c)	

(a) Excludes $397 million in 2006 classified as long-term debt at December 31, 2005
(b) *FPC Capital I – Quarterly Income Preferred Securities.*
(c) Rate is 3-month LIBOR, which was 4.54% at December 31, 2005
(d) Anticipated 10-year debt issue hedges mature on March 1, 2016, and required mandatory cash settlement on March 1, 2006

At December 31, 2005, we classified $397 million related to the retirement of $800 million of Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation did not require the use of working capital in 2006 as we had the intent and ability to refinance this debt on a long-term basis. On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, receiving net proceeds of$397 million. These senior notes are unsecured.

Marketable Securities Price Risk

The Utilities maintain trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning their nuclear plants. These funds are primarily invested in stocks, bonds and cash equivalents, which are exposed to price fluctuations in equity markets and to changes in interest rates. At December 31, 2006 and 2005, the fair value of these funds was $1.287 billion and $1.133 billion, respectively, including $735 million and $640 million, respectively, for PEC and $552 million and $493 million, respectively, for PEF. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

In connection with the acquisition of Florida Progress, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, are based on the net after-tax cash flows the facilities generate. These CVOs are recorded at fair value, and unrealized gains and losses from changes in fair value are recognized in earnings. At December 31, 2006 and 2005, the fair value of these CVOs was $32 million and $7 million, respectively. A hypothetical 10 percent decrease in the December 31, 2006, market price would result in a $3 million decrease in the fair value of the CVOs.

Commodity Price Risk

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of our ownership of energy-related assets. Our exposure to these fluctuations is significantly limited by the cost-based regulation of the Utilities. Each state commission allows electric utilities to recover certain of these costs through various cost-recovery clauses to the extent the respective commission determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. In addition, most of our long-term power sales contracts shift substantially all fuel price risk to the purchaser. We also have oil price risk exposure related to synthetic fuels tax credits as discussed in "Other Matters – Synthetic Fuels Tax Credits."

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

As discussed in Note 3, on December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of PVI's remaining CCO physical and commercial assets, and on July 12, 2006, our board of directors approved a plan to divest of Gas. The transaction to sell Gas closed on October 2, 2006. We expect to complete the disposition plan for CCO in 2007.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 Bcf of natural gas would be fulfilled. Therefore, these contracts were no longer treated as cash flow hedges and were dedesignated, and cash flow hedge accounting was discontinued.

At December 31, 2006, derivative assets and derivative liabilities related to CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. At December 31, 2005, derivative assets and derivative liabilities related to Gas and CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated

Balance Sheet. For the years ending December 31, 2006, 2005 and 2004, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ending December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2004, discontinued operations, net of tax includes $10 million in after-tax deferred losses, which were reclassified to earnings due to discontinuance of the related cash flow hedges.

We perform sensitivity analyses to estimate our exposure to the market risk of our derivative commodity instruments, which are not eligible for recovery from ratepayers. At December 31, 2006, as described above, these derivative commodity instruments are included in discontinued operations. The following discussion addresses the stand-alone commodity risk created by these derivative commodity instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge. The sensitivity analysis performed on these derivative commodity instruments uses quoted prices obtained from brokers to measure the potential loss in earnings from a hypothetical 10 percent adverse change in market prices over the next 12 months. A decrease of 10 percent in the market prices of energy commodities from their December 31, 2006, levels would decrease after-tax earnings of discontinued operations by approximately $55 million. A hypothetical 10 percent increase or decrease in commodity market prices in the near term on our derivative commodity instruments would not have had a material effect on our financial position, results of operations or cash flows at December 31, 2005. As discussed above, certain derivative contracts were dedesignated during 2006 and cash flow hedge accounting was discontinued, which increased the exposure to potential earnings impacts in the near term from changes in commodity market prices.

The above analysis of our derivative commodity instruments used for hedging purposes does not include the potential favorable impact of the same hypothetical price movement on the physical purchases of natural gas and power to which the hedges relate. Additionally, our derivative commodity portfolio is managed to complement the physical transaction portfolio, reducing overall risk within set limits. Therefore, the potential impact to earnings of discontinued operations from a hypothetical 10 percent adverse change in commodity market prices would be offset by a favorable impact on the underlying hedged physical transactions, assuming the derivative commodity positions are not closed out in advance of their expected term, continue to function effectively as hedges of the underlying risk, and the anticipated underlying transactions settle, as applicable. If any of these assumptions ceases to be true, a loss on the derivative instruments may occur.

See Note 17 for additional information with regard to our commodity contracts and use of derivative financial instruments.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our or the Utilities' results of operations during the years ended December 31, 2006, 2005 and 2004. Excluding $107 million of derivative assets, which are included in assets of discontinued operations on the Consolidated Balance Sheet and $31 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2006, we did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment at PEF, as discussed below. Our discontinued operations did not have material outstanding positions in such contracts at December 31, 2005.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2006, the fair values of these instruments were a $2 million long-term derivative asset position included in other assets and deferred debits, an $87 million short-term derivative liability position included in other current liabilities and a $36 million long-term derivative liability position included in other liabilities and deferred credits. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $49 million long-term derivative liability position included in other liabilities and deferred credits.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a NYMEX basis. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately eight million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts will be marked-to-market with changes in fair value recorded through earnings from synthetic fuels production.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2006, 2005 and 2004.

The fair values of commodity cash flow hedges at December 31 were as follows.

(in millions)	**2006**	2005
Fair value of assets	$2	$7
Fair value of liabilities	–	(4)
Fair value, net	$2	$3

Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. Excluded from the table above are $163 million of derivative assets, which are included in assets of discontinued operations, and $54 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2005.

At December 31, 2006, the amount recorded in our accumulated other comprehensive income (AOCI) related to commodity cash flow hedges was not material. At December 31, 2005, we had $69 million of after-tax deferred income recorded in AOCI related to commodity cash flow hedges.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of Progress Energy's management to establish and maintain adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15(d)-15(f) of the Securities Exchange Act of 1934, as amended. Progress Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Progress Energy, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, (3) provide reasonable assurance that receipts and expenditures of Progress Energy are being made only in accordance with authorizations of management and directors of Progress Energy; and (4) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Progress Energy's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of Progress Energy's internal control over financial reporting at December 31, 2006. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the board of directors.

Based on our assessment, management determined that, at December 31, 2006, Progress Energy maintained effective internal control over financial reporting.

Management's assessment of the effectiveness of Progress Energy's internal control over financial reporting at December 31, 2006, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

Robert B. McGehee

Robert B. McGehee
Chairman and Chief Executive Officer

Peter M Scott III

Peter M. Scott III
Executive Vice President and Chief Financial Officer

February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited management's assessment, included in the accompanying Management's Report of Internal Controls, that Progress Energy, Inc , and its subsidiaries (the "Company") maintained effective internal control over financial reporting at December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting at December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006, of the Company and our report dated February 28, 2007, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph concerning the adoption of new accounting principles

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Progress Energy, Inc.

We have audited the accompanying consolidated balance sheets of Progress Energy, Inc., and its subsidiaries (the Company) at December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 158, and in 2005 the Company adopted Statement of Financial Accounting Standards No. 123R and Financial Accounting Standards Board Interpretation No. 47.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting at December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2007, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
February 28, 2007

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data) Years ended December 31	2006	2005	2004
Operating revenues			
Electric	$8,722	$7,945	$7,153
Diversified business	848	1,223	900
Total operating revenues	9,570	9,168	8,053
Operating expenses			
Utility			
Fuel used in electric generation	3,008	2,359	2,011
Purchased power	1,100	1,048	868
Operation and maintenance	1,583	1,770	1,475
Depreciation and amortization	1,009	922	878
Taxes other than on income	500	460	425
Other	(3)	(37)	(13)
Diversified business			
Cost of sales	898	1,353	992
Depreciation and amortization	23	41	41
Impairments of assets	91	–	–
Gain on the sales of assets	(4)	(30)	(8)
Other	56	62	112
Total operating expenses	8,261	7,948	6,781
Operating income	1,309	1,220	1,272
Other income (expense)			
Interest income	61	16	11
Other, net	(18)	(7)	4
Total other income	43	9	15
Interest charges			
Net interest charges	632	587	572
Allowance for borrowed funds used during construction	(7)	(13)	(6)
Total interest charges, net	625	574	566
Income from continuing operations before income tax and minority interest	727	655	721
Income tax expense (benefit)	204	(37)	67
Income from continuing operations before minority interest	523	692	654
Minority interest in subsidiaries' (income) loss, net of tax	(9)	29	19
Income from continuing operations	514	721	673
Discontinued operations, net of tax	57	(25)	86
Cumulative effect of change in accounting principle, net of tax	–	1	–
Net income	$571	$697	$759
Average common shares outstanding – basic	250	247	242
Basic earnings per common share			
Income from continuing operations	$2.05	$2.92	$2.78
Discontinued operations, net of tax	0.23	(0.10)	0.35
Net income	$2.28	$2.82	$3.13
Diluted earnings per common share			
Income from continuing operations	$2.05	$2.92	$2.77
Discontinued operations, net of tax	0.23	(0.10)	0.35
Net income	$2.28	$2.82	$3.12
Dividends declared per common share	$2.43	$2.38	$2.32

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2006	2005
ASSETS		
Utility plant		
Utility plant in service	$23,743	$22,940
Accumulated depreciation	(10,064)	(9,602)
Utility plant in service, net	13,679	13,338
Held for future use	10	12
Construction work in progress	1,289	813
Nuclear fuel, net of amortization	267	279
Total utility plant, net	15,245	14,442
Current assets		
Cash and cash equivalents	265	605
~~Short-term investments~~	71	191
Receivables, net	930	997
Inventory	969	823
Deferred fuel cost	196	602
Deferred income taxes	159	37
Assets of discontinued operations	887	2,566
Prepayments and other current assets	108	186
Total current assets	3,585	6,007
Deferred debits and other assets		
Regulatory assets	1,231	854
Nuclear decommissioning trust funds	1,287	1,133
Diversified business property, net	31	78
Miscellaneous other property and investments	456	476
Goodwill	3,655	3,655
Intangibles, net	–	59
Other assets and deferred debits	211	358
Total deferred debits and other assets	6,871	6,613
Total assets	$25,701	$27,062
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 256 and 252 million shares issued and outstanding, respectively	$5,791	$5,571
Unearned ESOP shares (2 and 3 million shares, respectively)	(50)	(63)
Accumulated other comprehensive loss	(49)	(104)
Retained earnings	2,594	2,634
Total common stock equity	8,286	8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93
Minority interest	10	36
Long-term debt, affiliate	271	270
Long-term debt, net	8,564	10,176
Total capitalization	17,224	18,613
Current liabilities		
Current portion of long-term debt	324	513
Accounts payable	712	601
Interest accrued	171	208
Dividends declared	156	152
Short-term debt	–	175
Customer deposits	227	200
Liabilities of discontinued operations	189	542
Income taxes accrued	284	116
Other current liabilities	755	542
Total current liabilities	2,818	3,049
Deferred credits and other liabilities		
Noncurrent income tax liabilities	306	198
Accumulated deferred investment tax credits	151	163
Regulatory liabilities	2,543	2,527
Asset retirement obligations	1,306	1,242
Accrued pension and other benefits	957	865
Other liabilities and deferred credits	396	405
Total deferred credits and other liabilities	5,659	5,400
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$25,701	$27,062

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	2006	2005	2004
Operating activities			
Net income	**$571**	$697	$759
Adjustments to reconcile net income to net cash provided by operating activities			
(Income) loss from discontinued operations, net of tax	**(57)**	25	(86)
Gain on sales of operating assets	**(7)**	(67)	(21)
Impairment of long-lived assets and investments	**92**	–	–
Charges for voluntary enhanced retirement program	**–**	159	–
Depreciation and amortization	**1,119**	1,083	1,037
Deferred income taxes	**(72)**	(379)	(118)
Investment tax credit	**(12)**	(13)	(14)
Deferred fuel cost (credit)	**396**	(317)	(19)
Other adjustments to net income	**85**	157	113
Cash provided (used) by changes in operating assets and liabilities			
Receivables	**47**	(154)	16
Inventory	**(171)**	(136)	(84)
Prepayments and other current assets	**(71)**	(78)	19
Accounts payable	**46**	103	(30)
Other current liabilities	**(70)**	109	67
Regulatory assets and liabilities	**11**	(74)	(234)
Other liabilities and deferred credits	**(44)**	101	(60)
Other assets and deferred debits	**49**	(41)	64
Net cash provided by operating activities	**1,912**	1,175	1,409
Investing activities			
Gross utility property additions	**(1,423)**	(1,080)	(998)
Diversified business property additions	**(2)**	(6)	(6)
Nuclear fuel additions	**(114)**	(126)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	**1,654**	475	372
Purchases of available-for-sale securities and other investments	**(2,452)**	(3,985)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	**2,631**	3,845	3,248
Other investing activities	**(23)**	(37)	(30)
Net cash provided (used) by investing activities	**271**	(914)	(649)
Financing activities			
Issuance of common stock	**185**	208	73
Proceeds from issuance of long-term debt, net	**397**	1,642	421
Net (decrease) increase in short-term debt	**(175)**	(509)	680
Retirement of long-term debt	**(2,200)**	(564)	(1,112)
Dividends paid on common stock	**(607)**	(582)	(558)
Cash distributions to minority interests of consolidated subsidiary	**(79)**	–	–
Other financing activities	**11**	34	11
Net cash (used) provided by financing activities	**(2,468)**	229	(485)
Cash provided (used) by discontinued operations			
Operating activities	**86**	294	191
Investing activities	**(141)**	(232)	(199)
Financing activities	**–**	(2)	(246)
Net (decrease) increase in cash and cash equivalents	**(340)**	550	21
Cash and cash equivalents at beginning of year	**605**	55	34
Cash and cash equivalents at end of year	**$265**	$605	$55
Supplemental disclosures of cash flow information			
Cash paid during the year – interest (net of amount capitalized)	**$692**	$643	$639
income taxes (net of refunds)	**$311**	$168	$189

Noncash activities

- In addition to normal and recurring accruals for capital additions, Progress Energy Florida recorded purchases and construction costs for utility plant and equipment and a corresponding liability for $47 million related to additions at an electric generation facility in 2006. Actual cash expenditures will not occur until 2007.
- In 2005, Progress Energy Florida entered into a capital lease agreement for a building that was completed in 2006, at which point Progress Energy Florida recorded a capital lease asset and obligation for $54 million.

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned Restricted Shares	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total Common Stock Equity
Balance, December 31, 2003	246	$5,270	$(17)	$(89)	$(50)	$2,330	$7,444
Net income		–	–	–	–	759	759
Other comprehensive loss		–	–	–	(114)	–	(114)
Comprehensive income							645
Issuance of shares	1	62	–	–	–	–	62
Stock options exercised		18	–	–	–	–	18
Purchase of restricted stock		–	(7)	–	–	–	(7)
Restricted stock expense recognition		–	7	–	–	–	7
Cancellation of restricted shares		(4)	4	–	–	–	–
Allocation of ESOP shares		14	–	13	–	–	27
Dividends ($2.32 per share)		–	–	–	–	(563)	(563)
Balance, December 31, 2004	247	5,360	(13)	(76)	(164)	2,526	7,633
Net income		–	–	–	–	697	697
Other comprehensive income		–	–	–	60	–	60
Comprehensive income							757
Issuance of shares	5	199	–	–	–	–	199
Presentation reclassification – *SFAS No. 123R adoption*		(13)	13	–	–	–	–
Stock options exercised		8	–	–	–	–	8
Purchase of restricted stock		(8)	–	–	–	–	(8)
Restricted stock expense recognition		3	–	–	–	–	3
Allocation of ESOP shares		12	–	13	–	–	25
Stock-based compensation expense		10	–	–	–	–	10
Dividends ($2.38 per share)		–	–	–	–	(589)	(589)
Balance, December 31, 2005	**252**	**5,571**	–	**(63)**	**(104)**	**2,634**	**8,038**
Net income		–	–	–	–	**571**	**571**
Other comprehensive loss		–	–	–	**(18)**	–	**(18)**
Comprehensive income							**553**
Adjustment to initially apply SFAS No. 158, net of tax		–	–	–	**73**	–	**73**
Issuance of shares	**4**	**70**	–	–	–	–	**70**
Stock options exercised		**115**	–	–	–	–	**115**
Purchase of restricted stock		**(8)**	–	–	–	–	**(8)**
Restricted stock expense recognition		**5**	–	–	–	–	**5**
Allocation of ESOP shares		**13**	–	**13**	–	–	**26**
Stock-based compensation expense		**25**	–	–	–	–	**25**
Dividends ($2.43 per share)		–	–	–	–	**(611)**	**(611)**
Balance, December 31, 2006	**256**	**$5,791**	**$–**	**$(50)**	**$(49)**	**$2,594**	**$8,286**

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	2006	2005	2004
Net income	**$571**	$697	$759
Other comprehensive (loss) income			
Reclassification adjustment for amounts included in net income			
Cash flow hedges (net of tax benefit (expense) of $28, $(26) and $(16), respectively)	**(46)**	46	26
Foreign currency translation adjustments included in discontinued operations	–	(6)	–
Minimum pension liability adjustment included in discontinued operations (net of tax expense of $1)	–	1	–
Changes in net unrealized (losses) gains on cash flow hedges (net of tax benefit (expense) of $16, $(26) and $10, respectively)	**(23)**	37	(18)
Reclassification of minimum pension liability to regulatory assets (net of tax expense of $2)	–	–	4
Minimum pension liability adjustment (net of tax (expense) benefit of $(30), $22 and $78, respectively)	**48**	(19)	(130)
Foreign currency translation and other (net of tax expense of $–, $1 and $–, respectively)	**3**	1	4
Other comprehensive (loss) income	**(18)**	60	(114)
Comprehensive income	**$553**	$757	$645

See Notes to Consolidated Financial Statements

In this report, Progress Energy [which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis] is at times referred to as "we," "us" or "our." Additionally, we may collectively refer to our electric utility subsidiaries, Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF), as the "Utilities."

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization

The Parent is a holding company headquartered in Raleigh, N.C. As such, we are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the regulatory provisions of the Public Utility Holding Company Act of 2005 (PUHCA 2005). Prior to February 8, 2006, the Parent was subject to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA 1935), as amended.

Our reportable segments are: PEC, PEF and Coal and Synthetic Fuels. Our PEC and PEF segments are primarily engaged in the generation, transmission, distribution and sale of electricity. Our Coal and Synthetic Fuels segment is primarily engaged in the production and sale of coal-based solid synthetic fuels as defined under the Internal Revenue Code (the Code), the operation of synthetic fuels facilities for third parties, and coal terminal services. Our Corporate and Other segment (Corporate and Other) is comprised of the activities of the Parent and Progress Energy Service Company (PESC) as well as nonregulated businesses, which do not separately meet the disclosure requirements as a business segment.

PEC and PEF are regulated public utilities. PEC is subject to the regulatory provisions of the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC. PEF is subject to the regulatory provisions of the Florida Public Service Commission (FPSC), the NRC and the FERC.

See Note 19 for further information about our segments.

B. Basis of Presentation

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in minority interest in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for minority interest are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies (generally 20 percent to 50 percent ownership), are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20). Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 13 for more information about our investments.

Diversified business revenues and expenses represent the operating activities of our consolidated nonregulated operations, primarily the Coal and Synthetic Fuels segment. These operations are separate and distinct businesses from the Utilities.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the ratemaking process is probable.

These notes accompany and form an integral part of our consolidated financial statements.

Certain amounts for 2005 and 2004 have been reclassified to conform to the 2006 presentation.

C. Consolidation of Variable Interest Entities

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities for which we are the primary beneficiary in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 46R, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51" (FIN 46R).

In addition to the variable interests listed below for PEC and PEF, we have interests through other subsidiaries in several variable interest entities for which we are not the primary beneficiary. These arrangements include investments in five limited liability partnerships and limited liability corporations. At December 31, 2006, the aggregate additional maximum loss exposure that we could be required to record in our income statement as a result of these arrangements was $7 million, which represents our net remaining investment in the entities. The creditors of these variable interest entities do not have recourse to our general credit in excess of the aggregate maximum loss exposure.

PEC is the primary beneficiary of, and consolidates, two limited partnerships that qualify for federal affordable housing and historic tax credits under Section 42 of the Code. At December 31, 2006, the total assets of the two entities were $37 million, the majority of which are collateral for the entities' obligations and are included in miscellaneous other property and investments in the Consolidated Balance Sheet.

PEC has an interest in and consolidates a limited partnership that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. PEC has requested the necessary information to determine if the 17 partnerships are variable interest entities or to identify the primary beneficiaries; all entities from which the necessary financial information was requested declined to provide the information to PEC and, accordingly, PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the 17 partnerships. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the entities would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows.

PEC also has an interest in one power plant resulting from long-term power purchase contracts. Our only significant exposure to variability from these contracts results from fluctuations in the market price of fuel used by the entity's plants to produce the power purchased by PEC. We are able to recover these fuel costs under PEC's fuel clause. Total purchases from this counterparty were $45 million, $44 million and $42 million in 2006, 2005 and 2004, respectively. The generation capacity of the entity's power plant is approximately 835 megawatts (MW). PEC has requested the necessary information to determine if the power plant owner is a variable interest entity or to identify the primary beneficiary. The entity declined to provide us with the necessary financial information and PEC has applied the information scope exception in FIN 46R, paragraph 4(g), to the power plant. PEC believes that if it is determined to be the primary beneficiary of the entity, the effect of consolidating the entity would result in increases to total assets, long-term debt and other liabilities, but would have an insignificant or no impact on PEC's common stock equity, net earnings or cash flows. However, because PEC has not received any financial information from the counterparty, the impact cannot be determined at this time.

PEC also has interests in several other variable interest entities for which PEC is not the primary beneficiary. These arrangements include investments in 20 limited liability partnerships, limited liability corporations and venture capital funds and two building leases with special-purpose entities. At December 31, 2006, the aggregate maximum loss exposure that PEC could be required to record on its income statement as a result of these arrangements totals $21 million, which primarily represents its net remaining investment in these entities. The creditors of these variable interest entities do not have recourse to the general credit of PEC in excess of the aggregate maximum loss exposure.

PEF has interests in three variable interest entities for which PEF is not the primary beneficiary. These arrangements include investments in one venture capital fund, one building lease with a special-purpose entity and one operating lease with a special-purpose entity. At December 31, 2006, the aggregate maximum loss exposure that PEF could be required to record in its income statement as a result of these arrangements was $57 million. The majority of this exposure is related to a prepayment clause in the building lease and is not considered equity at risk. The creditors of these variable interest entities do not have recourse to the general credit of PEF in excess of the aggregate maximum loss exposure.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform to GAAP, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

REVENUE RECOGNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility revenues earned when service has been delivered but not billed by the end of the accounting period. Diversified business revenues are generally recognized at the time products are shipped or as services are rendered. Leasing activities are accounted for in accordance with SFAS No. 13, "Accounting for Leases." Revenues related to design and construction of wireless infrastructure are recognized upon completion of services for each completed phase of design and construction. Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

FUEL COST DEFERRALS

Fuel expense includes fuel costs or recoveries that are deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel costs and portions of purchased power costs through surcharges on customer rates. These deferred fuel costs are recognized in revenues and fuel expenses as they are billable to customers.

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis. The amount of gross receipts tax, franchise taxes and other excise taxes included in electric operating revenues and taxes other than on income in the Consolidated Statements of Income were $293 million, $258 million and $240 million, respectively, for the years ended December 31, 2006, 2005 and 2004.

STOCK-BASED COMPENSATION

Prior to July 2005, we accounted for stock-based compensation under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for our stock-based compensation costs. In addition, we followed the disclosure requirements contained in SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123), as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." Effective July 1, 2005, we adopted the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), for stock-based compensation utilizing the modified prospective transition method (See Note 10B).

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of PUHCA 1935. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered. The repeal of PUHCA 1935 and subsequent regulation by the FERC did not change our current intercompany services.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. Certain costs that would otherwise not be capitalized under GAAP are capitalized in accordance with regulatory treatment. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (including planned major maintenance activities), and replacements and renewals of items determined to be less than units of property, are charged to maintenance expense as incurred, with the exception of nuclear outages at PEF. Pursuant to a regulatory order, PEF accrues for nuclear outage costs in advance of scheduled outages, which occur every two years. The cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. Removal or disposal costs that do not represent asset retirement obligations under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), are charged to a regulatory liability.

Allowance for funds used during construction (AFUDC) represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform system of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income and the borrowed funds portion is credited to interest charges.

ASSET RETIREMENT OBLIGATIONS

We account for asset retirement obligations (ARO), which represent legal obligations associated with the retirement of certain tangible long-lived assets, in accordance with SFAS No. 143. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. In addition, effective December 31, 2005, we also adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), which clarified certain requirements of SFAS No. 143.

The adoption of SFAS No. 143 and FIN 47 had no impact on the income of the Utilities as the effects were offset by the establishment of regulatory assets and regulatory liabilities pursuant to SFAS No. 71 (See Note 7A) and in accordance with orders issued by the NCUC, the SCPSC and the FPSC.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

For financial reporting purposes, substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization of utility assets (See Note 5).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method. In the Utilities' retail jurisdictions, provisions for nuclear decommissioning costs are approved by the NCUC, the SCPSC and the FPSC and are based on site-specific estimates that include the costs for removal of all radioactive and other structures at the site. In the wholesale jurisdictions, the provisions for nuclear decommissioning costs are approved by the FERC.

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. During the rate freeze period, the legislation provides for the amortization and recovery of 70 percent of the original estimated compliance costs while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with a maturity of three months or less.

INVENTORY

We account for inventory, including emission allowances, using the average cost method. Inventories are valued at the lower of average cost or market.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to SFAS No. 71, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

DIVERSIFIED BUSINESS PROPERTY

Diversified business property is stated at cost less accumulated depreciation. If an impairment is recognized on an asset, the fair value becomes its new cost basis. The costs of renewals and betterments are capitalized. The costs of repairs and maintenance are charged to expense as incurred. For properties other than oil and gas properties, depreciation is computed on a straight-line basis using the estimated useful lives disclosed in Note 5B. Depletion of mineral rights is provided on the units-of-production method based upon the estimates of recoverable amounts of clean mineral.

We use the full-cost method to account for our oil and gas properties. Under the full-cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized. These capitalized costs include the costs of all unproved properties and internal costs directly related to acquisition and exploration activities. The amortization base also includes the estimated future cost to develop proved reserves. Except for costs of unproved properties and major development projects in progress, all costs are amortized using the units-of-production method on a country-by-country basis over the life of our proved reserves. Accordingly, all property acquisition, exploration, and development costs of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals, are capitalized as incurred, including internal costs directly attributable to such activities. Related interest expense incurred during property development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property are reclassified as proved property and well costs when related proved reserves are found. Costs to operate and maintain wells and field equipment are expensed as incurred. In accordance with Rule 4-10 of Regulation S-X, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless certain significance tests are met. During 2006, we sold our natural gas drilling and production business, and we met the significance tests necessary to recognize a gain on the transaction (See Note 3B).

GOODWILL AND INTANGIBLE ASSETS

Goodwill is subject to at least an annual assessment for impairment by applying a two-step, fair value-based test. This assessment could result in periodic impairment charges. Intangible assets are being amortized based on the economic benefit of their respective lives.

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

Long-term debt premiums, discounts and issuance expenses are amortized over the terms of the debt issues. Any expenses or call premiums associated with the reacquisition of debt obligations by the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 7A).

INCOME TAXES

Deferred income taxes have been provided for temporary differences. These occur when there are differences between the book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. Credits for the production and sale of synthetic fuels are deferred credits to the extent they cannot be or have not been utilized in the annual consolidated federal income tax returns, and are included in income tax expense (benefit) in the Consolidated Statements of Income. Interest expense on tax deficiencies is included in net interest charges and tax penalties are included in other, net on the Consolidated Statements of Income.

DERIVATIVES

We account for derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities – An Amendment of FASB Statement No. 133," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as assets or liabilities in the balance sheet and measure those instruments at fair value, unless the derivatives meet the SFAS No. 133 criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the SFAS No. 133 criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related SFAS No. 133 hedge criteria are met. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, including uncertain tax benefits, in accordance with SFAS No 5, "Accounting for Contingencies" (SFAS No. 5). Under SFAS No. 5, contingent losses such as unfavorable results of litigation are recorded when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. Tax reserves are recorded for uncertain tax benefits when it is probable that the tax position will be disallowed and the amount of the disallowance can be reasonably estimated. Unless otherwise required by GAAP, we do not accrue legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for SFAS No. 5 have been met. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

As discussed in Note 9, we account for impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). We review the recoverability of long-lived tangible and intangible assets whenever indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

We review our investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider various factors, such as the investee's cash position, earnings and revenue outlook, liquidity and management's ability to raise capital in determining whether the decline is other-than-temporary. If we determine that an other-than-temporary decline in value exists, the investments are written down to fair value with a new cost basis established.

Under the full-cost method of accounting for oil and gas properties, total capitalized costs are limited to a ceiling based on the present value of discounted (at 10%) future net revenues using current prices, plus the lower of cost or fair market value of unproved properties. The ceiling test takes into consideration the prices of qualifying cash flow hedges as of the balance sheet date. If the ceiling (discounted revenues) is not equal to or greater than total capitalized costs, we are required to write-down capitalized costs to this level. We performed this ceiling test calculation every quarter prior to the sale of our natural gas drilling and production business (See Note 3B). No write-downs were required in 2006, 2005 or 2004.

SUBSIDIARY STOCK TRANSACTIONS

Gains and losses realized as a result of common stock sales by our subsidiaries are recorded in the Consolidated Statements of Income, except for any transactions that must be credited directly to equity in accordance with the provisions of Staff Accounting Bulletin No. 51, "Accounting for Sales of Stock by a Subsidiary."

2. NEW ACCOUNTING STANDARDS

SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS No. 158). SFAS No. 158 requires an entity to recognize in its statement of financial condition the funded status of its pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the employer's fiscal year (with limited exceptions) SFAS No 158 also requires an entity to recognize changes in the funded status of a pension or other postretirement benefit plan within accumulated other comprehensive income (AOCI), net of tax, to the extent such changes are not recognized in earnings as components of net periodic cost. SFAS No 158 does not permit retrospective application of its provisions. The recognition and disclosure provisions of SFAS No. 158 were implemented by us as of December 31, 2006. The implementation of SFAS No. 158 had no impact on reported net income

The following is a summary of the incremental effect of applying the provisions of SFAS No. 158 on individual line items of the Consolidated Balance Sheet at December 31, 2006.

(in millions)	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory assets	$892	$339	$1,231
Intangibles, net	39	(39)	–
Total assets	25,401	300	25,701
Liabilities of discontinued operations	185	4	189
Income taxes accrued	287	(3)	284
Other current liabilities	746	9	755
Noncurrent income tax liabilities	255	51	306
Accrued pension and other benefits	791	166	957
Accumulated other comprehensive loss	(122)	73	(49)
Total capitalization and liabilities	25,401	300	25,701

Amounts for the Utilities that would otherwise be recorded in AOCI pursuant to SFAS No. 158 are recorded as regulatory assets consistent with the recovery of the related costs through the ratemaking process.

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). Enterprises must adopt FIN 48 through a cumulative effect adjustment to retained earnings at the beginning of their first fiscal year that begins after December 15, 2006, which for us was January 1, 2007 FIN 48 applies to all tax positions within the scope of SFAS No 109, "Accounting for Income Taxes," and includes tax positions taken and tax positions expected to be taken A two-step process is required for the application of FIN 48: recognition of the tax benefit based on a "more likely than not" threshold and measurement of the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with the taxing authority FIN 48 also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. We are still in the process of assessing the impact of FIN 48 on our various income tax positions. The cumulative effect adjustment to retained earnings upon adoption of FIN 48 could have a material impact on our financial statements.

SFAS No. 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 redefines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." SFAS No. 157 establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. We will implement SFAS No. 157 as of January 1, 2008, applying the provisions retrospectively for derivative accounting and prospectively for all other valuations. We are currently evaluating the impact adoption may have on our financial condition, results of operations and cash flows.

Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). In practice, some companies currently use the "rollover" method, which focuses on the impact of a misstatement on the income statement. Other companies use the "iron curtain" method, which focuses on the impact of a misstatement on the balance sheet SAB 108 requires companies to use a "dual approach" in quantifying financial statement misstatements. If an error is determined to be material under either approach, the financial statements must be adjusted. SAB 108 also provides transition guidance for correcting errors existing in prior years

The SEC permits two methods for the initial application of SAB 108 A company can elect to restate prior financial statements as if the "dual approach" had always been used, or it can record a cumulative effect, with any correcting adjustments recorded to the carrying values of assets and liabilities as of the beginning of the implementation year with the offsetting adjustment recorded to the opening balance of retained earnings. Companies using the "cumulative effect" transition method must disclose the nature and amount of each individual error, including when and how each error being corrected arose. They must also disclose the fact that the errors had previously been considered immaterial. Companies do not have to restate prior period financial statements at initial application so long as management properly applied its previous approach.

SAB 108 is effective for us at December 31, 2006. The implementation of SAB 108 did not have a material effect on our financial position or results of operations, and we did not record an adjustment to beginning retained earnings as permitted by SAB 108.

3. DIVESTITURES

A. CCO – Georgia Operations

On December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of Progress Ventures, Inc.'s (PVI) Competitive Commercial Operations (CCO) physical and commercial assets, which include approximately 1,900 MW of power generation facilities in Georgia, as well as forward gas and power contracts, gas transportation, storage and structured power and other contracts, including the full requirements contracts with 16 Georgia Electric Membership Cooperatives (the Georgia Contracts). The operations of CCO were previously included in the former Progress Ventures segment. We expect to complete the disposition plan in 2007. As a result of the disposition plan, we recorded an after-tax estimated loss of $226 million in December 2006. In 2007, we anticipate recording additional material charges in discontinued operations related to the disposition plan. These additional charges relate primarily to costs to be incurred to exit the Georgia Contracts under SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." These costs could exceed $200 million after-tax.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of CCO as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $36 million, $39 million and $40 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in December 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $14 million, $14 million and $15 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2006	2005	2004
Revenues	$754	$627	$168
Loss before income taxes	$(92)	$(93)	$(39)
Income tax benefit	35	39	16
Net loss from discontinued operations	(57)	(54)	(23)
Estimated loss on disposal of discontinued operations, including income tax benefit of $123	(226)	–	–
Loss from discontinued operations	$(283)	$(54)	$(23)

B. Natural Gas Drilling and Production

On October 2, 2006, we sold our natural gas drilling and production business (Gas) to EXCO Resources, Inc. for approximately $1.1 billion in net proceeds. Gas included Winchester Production Company, Ltd. (Winchester Production), Westchester Gas Company, Texas Gas Gathering and Talco Midstream Assets Ltd.; all were subsidiaries of Progress Fuels Corporation (Progress Fuels). Proceeds from the sale have been used primarily to reduce holding company debt and for other corporate purposes.

Based on the net proceeds associated with the sale, we recorded an after-tax net gain on disposal of $300 million during the year ended December 31, 2006.

In December 2004, we sold certain gas-producing properties and related assets owned by Winchester Production, which were previously included in the former Progress Ventures segment. Net proceeds of approximately $251 million were used to reduce debt. Because the sale significantly altered the ongoing relationship between capitalized costs and remaining proved reserves, under the full-cost method of accounting, the pre-tax gain of $56 million was recognized in earnings rather than as a reduction of the basis of our remaining oil and gas properties. Upon the sale of Gas, the gain was reclassed from continuing operations to earnings from discontinued operations.

The accompanying consolidated financial statements have been restated for all periods presented to reflect all the operations of Gas as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended

December 31, 2006, 2005 and 2004 was $13 million, $13 million and $14 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in July 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $16 million, $26 million and $27 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2006	2005	2004
Revenues	$192	$159	$162
Earnings before income taxes	$135	$73	$127
Income tax expense	(53)	(25)	(51)
Net earnings from discontinued operations	82	48	76
Gain on disposal of discontinued operations, including income tax expense of $188	300	–	–
Earnings from discontinued operations	$382	$48	$76

C. CCO – DeSoto and Rowan Generation Facilities

On May 2, 2006, our board of directors approved a plan to divest of two subsidiaries of PVI, DeSoto County Generating Co., LLC (DeSoto) and Rowan County Power, LLC (Rowan). DeSoto owns a 320 MW dual-fuel combustion turbine electric generation facility in DeSoto County, Fla., and Rowan owns a 925 MW dual-fuel combined cycle and combustion turbine electric generation facility in Rowan County, N.C. On May 8, 2006, we entered into definitive agreements to sell DeSoto and Rowan, including certain existing power supply contracts, to Southern Power Company, a subsidiary of Southern Company, for gross purchase prices of approximately $80 million and $325 million, respectively. We used the proceeds from the sales to reduce debt and for other corporate purposes.

The sale of DeSoto closed in the second quarter of 2006 and the sale of Rowan closed during the third quarter of 2006. Based on the gross proceeds associated with the sales, we recorded an after-tax loss on disposal of $67 million during the year ended December 31, 2006.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of DeSoto and Rowan as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $6 million, $13 million and $13 million, respectively. We ceased recording depreciation upon classification of the assets as discontinued operations in May 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $3 million, $8 million and $8 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2006	2005	2004
Revenues	$64	$67	$72
Earnings before income taxes	$15	$5	$13
Income tax expense	(5)	(2)	(5)
Net earnings from discontinued operations	10	3	8
Loss on disposal of discontinued operations, including income tax benefit of $37	(67)	–	–
(Loss) earnings from discontinued operations	$(57)	$3	$8

D. Progress Telecom, LLC

On March 20, 2006, we completed the sale of Progress Telecom, LLC (PT LLC) to Level 3 Communications, Inc. (Level 3). We received gross proceeds comprised of cash of $69 million and approximately 20 million shares of Level 3 common stock valued at an estimated $66 million on the date of the sale. Our net proceeds from the sale of approximately $70 million, after consideration of minority interest, were used to reduce debt. Prior to the sale, we had a 51 percent interest in PT LLC. See Note 20 for a discussion of the subsequent sale of the Level 3 stock.

Based on the net proceeds associated with the sale and after consideration of minority interest, we recorded an after-tax net gain on disposal of $28 million during the year ended December 31, 2006.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of PT LLC as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated was $1 million for each of the years ended December 31, 2005 and 2004. We ceased recording depreciation upon classification of the assets as discontinued operations in January 2006. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $1 million, $8 million and $6 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2006	2005	2004
Revenues	$18	$76	$69
Earnings (loss) before income taxes and minority interest	$7	$11	$(9)
Income tax (expense) benefit	(4)	(3)	2
Minority interest	(5)	(4)	–
Net (loss) earnings from discontinued operations	(2)	4	(7)
Gain on disposal of discontinued operations, including income tax expense of $8 and minority interest of $35	28	–	–
Earnings (loss) from discontinued operations	$26	$4	$(7)

In connection with the sale, PEC and PEF provided indemnification against costs associated with certain asset performances to Level 3. See general discussion of guarantees at Note 22C. The ultimate resolution of these matters could result in adjustments to the gain on sale in future periods.

E. Dixie Fuels and Other Fuels Business

On March 1, 2006, we sold our 65 percent interest in Dixie Fuels Limited (Dixie Fuels) to Kirby Corporation for $16 million in cash. Dixie Fuels operates a fleet of four ocean-going dry-bulk barge and tugboat units operating under long-term contracts with PEF. Dixie Fuels primarily transports coal from the lower Mississippi River to Progress Energy's Crystal River facility. We recorded an after-tax gain of $2 million on the sale of Dixie Fuels. The other fuels business is Progress Materials, Inc. and is expected to be sold in 2007.

The accompanying consolidated financial statements have been restated for all periods presented to reflect Dixie Fuels and the other fuels business as discontinued operations. Interest expense has been allocated to discontinued operations based on their respective net assets, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated was $1 million for each of the years ended December 31, 2006, 2005 and 2004. We ceased recording depreciation upon classification of the assets as discontinued operations. After-tax depreciation expense during the years ended December 31, 2006, 2005 and 2004 was $1 million, $2 million and $3 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2006	2005	2004
Revenues	$20	$32	$25
Earnings before income taxes	$11	$8	$3
Income tax expense	(4)	(3)	(1)
Net earnings from discontinued operations	7	5	2
Gain on disposal of discontinued operations, including income tax expense of $1	2	–	–
Earnings from discontinued operations	$9	$5	$2

F. Coal Mining Businesses

On November 14, 2005, our board of directors approved a plan to divest of five subsidiaries of Progress Fuels engaged in the coal mining business. On May 1, 2006, we sold certain net assets of three of our coal mining businesses to Alpha Natural Resources, LLC for gross proceeds of $23 million plus a $4 million working capital adjustment. As a result, during the year ended December 31, 2006, we recorded an after-tax loss of $10 million on the sale of these assets. The remaining coal mining operations are expected to be sold in 2007.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the coal mining operations as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of the coal mines, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2006, 2005 and 2004 was $1 million, $3 million and $3 million, respectively. We ceased recording depreciation expense upon classification of the coal mining operations as discontinued operations in November 2005. After-tax depreciation expense during the years ended December 31, 2005 and 2004 was $10 million and $9 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	2006	2005	2004
Revenues	$84	$184	$160
Loss before income taxes	$(11)	$(16)	$(17)
Income tax benefit	7	5	12
Net loss from discontinued operations	(4)	(11)	(5)
Loss on disposal of discontinued operations, including income tax benefit of $16	(10)	–	–
Loss from discontinued operations	$(14)	$(11)	$(5)

G. Progress Rail

On March 24, 2005, we completed the sale of Progress Rail Services Corporation (Progress Rail) to One Equity Partners LLC, a private equity firm unit of J.P. Morgan Chase & Co. Cash proceeds from the sale were approximately $429 million, consisting of $405 million base proceeds plus a working capital adjustment. Proceeds from the sale were used to reduce debt.

Based on the gross proceeds associated with the sale of $429 million, we recorded an estimated after-tax loss on disposal of $25 million during the year ended December 31, 2005. During the year ended December 31, 2006, we recorded an additional after-tax loss on disposal of $6 million in connection with guarantees and indemnifications provided by Progress Fuels and Progress Energy for certain legal, tax and environmental matters to One Equity Partners, LLC. The ultimate resolution of these matters could result in adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

The accompanying consolidated financial statements have been restated for all periods presented to reflect the operations of Progress Rail as discontinued operations. Interest expense has been allocated to discontinued operations based on the net assets of Progress Rail, assuming a uniform debt-to-equity ratio across our operations. Interest expense allocated for the years ended December 31, 2005 and 2004 was $4 million and $16 million, respectively. We ceased recording depreciation upon classification of Progress Rail as discontinued operations in February 2005. After-tax depreciation expense during the years ended December 31, 2005 and 2004 was $3 million and $10 million, respectively. Results of discontinued operations for the years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Revenues	**$–**	$358	$1,127
Earnings before income taxes	**$–**	$8	$50
Income tax expense	**–**	(3)	(21)
Net earnings from discontinued operations	**–**	5	29
Loss on disposal of discontinued operations, including income tax (expense) benefit of $(6) and $15, respectively	**(6)**	(25)	–
(Loss) earnings from discontinued operations	**$(6)**	$(20)	$29

In February 2004, we sold the majority of the assets of Railcar Ltd., a subsidiary of Progress Rail, to The Andersons, Inc. for proceeds of approximately $82 million before transaction costs and taxes of approximately $13 million. In 2002, we had recognized pre-tax impairment of $59 million to write-down the assets to our estimated fair value less costs to sell. In July 2004, we sold the remaining assets, which had been classified as held for sale, to a third party for net proceeds of $6 million.

H. Net Assets of Discontinued Operations

Included in net assets of discontinued operations are the assets and liabilities of CCO, the remaining coal mining operations and other fuels business at December 31, 2006, and the assets and liabilities of CCO, Gas, DeSoto and Rowan, PT LLC, Dixie Fuels, the five coal mining businesses and other fuels business at December 31, 2005. The major balance sheet classes included in assets and liabilities of discontinued operations in the Consolidated Balance Sheets were as follows:

(in millions)	**December 31, 2006**	December 31, 2005
Accounts receivable	**$45**	$115
Inventory	**24**	50
Other current assets	**28**	47
Total property, plant and equipment, net	**573**	1,899
Total other assets	**217**	455
Assets of discontinued operations	**$887**	$2,566
Accounts payable	**$43**	$87
Accrued expenses	**122**	233
Long-term liabilities	**24**	222
Liabilities of discontinued operations	**$189**	$542

I. Winter Park Distribution Assets

As discussed in Note 7C, PEF sold certain electric distribution assets to Winter Park, Fla. (Winter Park), on June 1, 2005.

J. Synthetic Fuels Partnership Interests

In two June 2004 transactions, Progress Fuels sold a combined 49.8 percent partnership interest in Colona Synfuel Limited Partnership, LLLP (Colona), one of its synthetic fuels facilities. Substantially all proceeds from the sales will be received over time, which is typical of such sales in the industry. Gains from the sales will be recognized on a cost-recovery basis. The book value of the interests sold totaled approximately $5 million. We recognized gains on these transactions of $4 million, $30 million and $8 million in the years ended December 31, 2006, 2005 and 2004, respectively. In the event that the synthetic fuels tax credits from the Colona facility are reduced, including an increase in the price of oil that could limit or eliminate synthetic fuels tax credits, the amount of proceeds realized from the sale could be significantly impacted

K. North Carolina Natural Gas Corporation

On September 30, 2003, we sold North Carolina Natural Gas Corporation (NCNG) and our equity investment in Eastern North Carolina Natural Gas Company to Piedmont Natural Gas Company, Inc During 2004, we recorded an additional tax gain of approximately $6 million due to final tax adjustments related to the divestiture of NCNG

4. ACQUISITIONS

In May 2005, Winchester Production, an indirectly wholly owned subsidiary of Progress Fuels, acquired a 50 percent interest in approximately 11 natural gas producing wells and proven reserves of approximately 25 billion cubic feet equivalent (Bcf) from a privately owned company headquartered in Texas. In addition to the natural gas reserves, the transaction also included a 50 percent interest in the gas gathering systems related to these reserves The total cash purchase price for the transaction was $46 million. The pro forma results of operations reflecting the acquisition would not be materially different than the reported results of operations for 2005 or 2004. In 2006, we sold our 50 percent interest in the wells, reserves and gas gathering system as part of our transaction with EXCO Resources, Inc. (See Note 3B).

5. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

The balances of electric utility plant in service at December 31 are listed below, with a range of depreciable lives (in years) for each:

(in millions)	Depreciable Lives	2006	2005
Production plant	7-43	**$12,685**	$12,489
Transmission plant	17-75	**2,509**	2,353
Distribution plant	13-55	**7,351**	7,015
General plant and other	5-35	**1,198**	1,083
Utility plant in service		**$23,743**	$22,940

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 12C)

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2 7%, 2 5% and 2 2% in 2006, 2005 and 2004, respectively. The depreciation provisions related to utility plant were $628 million, $556 million and $463 million in 2006, 2005 and 2004, respectively. In addition to utility plant depreciation provisions, depreciation and amortization expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5D), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 21B).

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the U.S. Department of Energy (DOE) and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2006, 2005 and 2004 was $140 million, $136 million and $137 million, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

During 2004, PEC met the requirements of both the NCUC and the SCPSC for the implementation of two depreciation studies that allowed the utility to reduce the rates used to calculate depreciation expense. The reduction was primarily due to extended lives at each of PEC's nuclear units The reduced depreciation rates were effective January 1, 2004.

Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, for the years ended December 31, 2006, 2005 and 2004 was $140 million, $136 million and $137 million, respectively. These costs were included in fuel used for electric generation in the Consolidated Statements of Income

B. Diversified Business Property

The balances of diversified business property at December 31, with a range of depreciable lives for each, follows:

(in millions)	2006	2005
Equipment (3-25 years)	$66	$79
Land and mineral rights	16	17
Buildings and plants (5-40 years)	54	66
Rail equipment (3-20 years)	–	37
Computers, office equipment and software (3-10 years)	2	2
Construction work in progress	1	2
Accumulated depreciation	(108)	(125)
Diversified business property, net	$31	$78

Diversified business depreciation expense was $13 million for December 31, 2006, and $22 million for December 31, 2005 and 2004.

C. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). The co-owner of Intercession City Unit P11 has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31:

In the tables below, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris), which are not applicable to the joint owner's ownership interest in Harris.

D. Asset Retirement Obligations

At December 31, 2006 and 2005, the asset retirement costs, included in utility plant, related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $156 million and $168 million, respectively. The fair value of funds set aside in the Utilities' nuclear decommissioning trust funds for the nuclear decommissioning liability totaled $1.287 billion and $1.133 billion at December 31, 2006 and 2005, respectively. Net nuclear decommissioning trust unrealized gains are included in regulatory liabilities (See Note 7A).

2006

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$517	$263	$–
PEC	Harris	83.83%	3,159	1,489	18
PEC	Brunswick	81.67%	1,632	941	15
PEC	Roxboro Unit 4	87.06%	356	163	1
PEF	Crystal River Unit 3	91.78%	811	452	76
PEF	Intercession City Unit P11	66.67%	23	7	–

2005

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$518	$255	$1
PEC	Harris	83.83%	3,146	1,459	17
PEC	Brunswick	81.67%	1,623	921	23
PEC	Roxboro Unit 4	87.06%	355	153	10
PEF	Crystal River Unit 3	91.78%	808	493	48
PEF	Intercession City Unit P11	66.67%	24	4	–

Our decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2006, 2005 and 2004. Management believes that decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that are not SFAS No. 143 asset retirement obligations, which are included in depreciation and amortization expense, were $123 million, $168 million and $160 million in 2006, 2005 and 2004, respectively.

During 2005, PEF performed a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study decreased the rates used to calculate cost of removal expense with a resulting decrease of approximately $55 million in 2006.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 7A). At December 31, such costs consisted of:

(in millions)	**2006**	2005
Removal costs	**$1,341**	$1,316
Nonirradiated decommissioning costs	**137**	132
Dismantlement costs	**124**	123
Non-ARO cost of removal	**$1,602**	$1,571

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC's most recent site-specific estimates of decommissioning costs were developed in 2004, using 2004 cost factors, and are based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2004 dollars, were $569 million for Unit No. 2 at Robinson Nuclear Plant (Robinson), $418 million for Brunswick Nuclear Plant (Brunswick) Unit No. 1, $444 million for Brunswick Unit No. 2, and $775 million for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. Extended NRC operating licenses held by PEC currently expire in July 2030, December 2034 and September 2036 for Robinson and Brunswick Units No. 2 and No. 1, respectively. An application to extend the licenses 20 years for the Brunswick units was approved in June 2006. The NRC operating license held by PEC for Harris currently expires in October 2026. An application to extend this license 20 years was submitted in the fourth quarter of 2006. Based on updated assumptions, in 2005 PEC reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $14 million and $49 million, respectively.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF filed a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) with the FPSC on April 29, 2005, as part of PEF's base rate filing. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2005 dollars, is $614 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. The NRC operating license held by PEF for CR3 currently expires in December 2016. An application to extend this license 20 years is expected to be submitted in the first quarter of 2009. As part of this new estimate and assumed license extension, PEF reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $36 million and $94 million, respectively. In addition, we reduced PEF-related asset retirement costs, net of accumulated depreciation, by an additional $53 million at Progress Energy. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended through December 2005 under the terms of a previous base rate agreement, and the base rate agreement resulting from a base rate proceeding in 2005 continues that suspension. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF filed an updated fossil dismantlement study with the FPSC on April 29, 2005, as part of its base rate filing. PEF's reserve for fossil plant dismantlement was approximately $145 million at December 31, 2006 and 2005, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended through December 2005 under the terms of PEF's previous base rate agreement. The base rate agreement resulting from a base rate proceeding in 2005 continued the suspension of PEF's collection from customers of the expenses to dismantle fossil plants (See Note 7C).

Upon implementation of FIN 47 as of December 31, 2005, the Utilities recognized additional ARO liabilities for asbestos abatement costs (See Note 1D).

We have identified but not recognized AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by us. These easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The ARO is not estimable for such easements, as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO would be recorded at that time.

Our nonregulated AROs relate to the synthetic fuels operations. The related asset retirement costs, net of accumulated depreciation, totaled $3 million at December 31, 2006 and 2005.

The following table presents the changes to the AROs during the years ended December 31, 2006 and 2005. Additions relate primarily to asbestos abatement at the Utilities. Revisions to prior estimates of the PEC regulated ARO are related to remeasuring the nuclear decommissioning costs of irradiated plants to take into account updated site-specific decommissioning cost studies, which are required by the NCUC every five years. Revisions to prior estimates of the PEF regulated ARO are related to the updated cost estimate for nuclear decommissioning described above.

(in millions)	Regulated	Nonregulated
Asset retirement obligations at January 1, 2005	$1,261	$2
Additions	50	–
Accretion expense	65	1
Revisions to prior estimates	(137)	–
Asset retirement obligations at December 31, 2005	1,239	3
Accretion expense	**72**	–
Revisions to prior estimates	**(8)**	–
Asset retirement obligations at December 31, 2006	**$1,303**	**$3**

E. Insurance

The Utilities are members of Nuclear Electric Insurance Limited (NEIL), which provides primary and excess insurance coverage against property damage to members' nuclear generating facilities. Under the primary program, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under NEIL, following a 12-week deductible period, for 52 weeks in the amount of $4 million per week at the Brunswick, Harris and Robinson plants, and $5 million per week at the Crystal River plant. An additional 110 weeks of coverage is provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $33 million with respect to the primary coverage, $36 million with respect to the decontamination, decommissioning and excess property coverage, and $24 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $10.760 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from an insured nuclear incident exceed $300 million (currently available through commercial insurers), each company would be subject to pro rata assessments of up to $100 million for each reactor owned per occurrence. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $15 million per reactor owned.

Under the NEIL policies, if there were multiple terrorism losses occurring within one year, NEIL would make available one industry aggregate limit of $3.200 billion, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply. For nuclear liability claims arising out of terrorist acts, the primary level available through commercial insurers is now subject to an industry aggregate limit of $300 million. The second level of coverage obtained through the assessments discussed above would continue to apply to losses exceeding $300 million and would provide coverage in excess of any diminished primary limits due to terrorist acts.

The Utilities self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF maintains a storm damage reserve pursuant to a regulatory order and may defer losses in excess of the reserve (See Note 7C).

6. CURRENT ASSETS

A. Receivables

Income tax receivables and interest income receivables are not included in receivables. These amounts are included in prepaids and other current assets on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

(in millions)	2006	2005
Trade accounts receivable	$628	$661
Unbilled accounts receivable	227	227
Notes receivable	57	83
Other receivables	46	45
Allowance for doubtful accounts receivable	(28)	(19)
Total receivables	$930	$997

B. Inventory

At December 31 inventory was comprised of:

(in millions)	2006	2005
Fuel for production	$470	$321
Inventory for sale	34	61
Materials and supplies	443	406
Emission allowances	22	35
Total current inventory	$969	$823

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits for Progress Energy of $44 million at December 31, 2006 and 2005.

Emission allowances above exclude $14 million of long-term emission allowances included in other assets and deferred debits at December 31, 2005. We did not have any long-term emission allowance amounts at December 31, 2006.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of SFAS No. 71. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of SFAS No. 71 could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event could result in an impairment of utility plant assets as determined pursuant to SFAS No. 144.

At December 31 the balances of regulatory assets (liabilities) were as follows.

(in millions)	2006	2005
Deferred fuel cost – current (Note 7B)	$196	$602
Deferred fuel cost – long-term (Note 7B)	114	31
Deferred impact of ARO – PEC (Note 1D)	282	281
Income taxes recoverable through future rates (Note 14)	114	81
Loss on reacquired debt (Note 1D)	46	50
Storm deferral (Notes 7B and 7C)	102	227
Postretirement benefits (Note 16)	373	88
Derivative mark-to-market adjustment (Note 17)	78	6
Environmental (Notes 7B, 7C and 21A)	72	26
Other	50	64
Total long-term regulatory assets	1,231	854
Deferred fuel cost – current (Note 7C)	(63)	–
Deferred energy conservation cost and other current regulatory liabilities	(13)	(10)
Total current regulatory liabilities	(76)	(10)
Non-ARO cost of removal (Note 5D)	(1,602)	(1,571)
Deferred impact of ARO – PEF (Note 1D)	(221)	(225)
Net nuclear decommissioning trust unrealized gains (Note 5D)	(330)	(251)
Clean Smokestacks Act compliance (Note 21B)	(333)	(317)
Derivative mark-to-market adjustment (Note 17A)	–	(122)
Other	(57)	(41)
Total long-term regulatory liabilities	(2,543)	(2,527)
Net regulatory liabilities	$(1,192)	$(1,081)

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory assets earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that do not incur a carrying cost. We expect to fully recover these assets and refund these liabilities through customer rates under current regulatory practice.

B. PEC Retail Rate Matters

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. As further discussed in Note 21B, the Clean Smokestacks Act was enacted in 2002. The Clean Smokestacks Act freezes North Carolina electric utility base rates for a five-year period ending in December 2007, unless there are extraordinary events beyond the control of the utilities or unless the utilities persistently earn a return substantially in excess of the rate of return established and found reasonable by the NCUC in the respective utility's last general rate case. During the rate freeze period, the legislation provides for the amortization and recovery of 70 percent of the original estimated compliance costs while providing significant flexibility in the amount of annual amortization recorded from none up to $174 million per year. Subsequent to 2007, PEC's current North Carolina base rates will continue subject to traditional cost-based rate regulation.

FUEL COST RECOVERY

On May 3, 2006, PEC filed with the SCPSC for an increase in the fuel rate charged to its South Carolina ratepayers for under-recovered fuel costs and to meet future expected fuel costs. On June 16, 2006, the SCPSC approved a settlement agreement filed jointly by PEC and all other parties to the proceeding. The settlement agreement provided for a $23 million, or 4.6 percent, increase in rates. The increase was $4 million less than PEC originally requested due to adjustment of future fuel cost estimates agreed upon during settlement. Effective July 1, 2006, residential electric bills increased by $3.01 per 1,000 kWh for fuel cost recovery. At December 31, 2006, PEC's South Carolina deferred fuel balance was $29 million, of which $5 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

On June 2, 2006, PEC filed with the NCUC for an increase in the fuel rate charged to its North Carolina ratepayers. On September 25, 2006, the NCUC approved a settlement agreement filed jointly by PEC, the NCUC Public Staff and the Carolinas Industrial Group for Fair Utility Rates II. The settlement agreement provided for a $177 million, or 6.7 percent, increase in rates effective October 1, 2006. The settlement agreement further provides for rate increases of $50 million in 2007 and $30 million in 2008 and for PEC to collect its existing deferred fuel balance by September 30, 2009. PEC initially sought an increase of $292 million, or 11.0 percent, but agreed to a three-year phase-in of the increase in order to address concerns regarding the magnitude of the proposed increase. PEC will be allowed to calculate and collect interest at 6% on the difference between its fuel factor proposed in its original request to the NCUC and the settlement agreement's factor. Effective October 1, 2006, residential electric bills increased by $4.87 per 1,000 kWh for fuel cost recovery. At December 31, 2006, PEC's North Carolina deferred fuel balance was $281 million, of which $109 million is expected to be collected after 2007 in accordance with the settlement agreement and, therefore, has been classified as a long-term regulatory asset.

The Carolina Utility Customers Association (CUCA) appealed the NCUC's order on November 21, 2006, on the grounds that the NCUC does not have the statutory authority to establish fuel rates for more than one year. We anticipate filing a motion to dismiss during the first quarter of 2007. We cannot predict the outcome of this matter.

STORM COST RECOVERY

In February 2004, PEC filed with the SCPSC seeking permission to defer expenses incurred from the first quarter 2004 winter storm. In September 2004, the SCPSC approved PEC's request to defer the costs and amortize them ratably over five years beginning in January 2005. Approximately $9 million related to storm costs was deferred in 2004. During each of 2006 and 2005, PEC recognized $2 million of South Carolina storm amortization.

In October 2003, PEC filed with the NCUC seeking permission to defer approximately $24 million of expenses incurred from Hurricane Isabel and the February 2003 winter storms. In December 2003, the NCUC approved PEC's request to defer the costs associated with Hurricane Isabel and the February 2003 winter storms and amortize them over a period of five years. During each of 2006, 2005 and 2004, PEC recognized $5 million of North Carolina storm amortization.

OTHER MATTERS

PEC filed petitions on September 14, 2006, and September 22, 2006, with the SCPSC and NCUC, respectively, seeking authorization to defer and amortize $18 million of previously recorded operation and maintenance (O&M) expense relating to certain environmental remediation sites (See Note 21A). On October 11, 2006, the SCPSC granted PEC's petition to defer its jurisdictional amount, totaling $3 million, and amortize it over a five-year period beginning January 1, 2007. On October 19, 2006, the NCUC granted PEC's petition to defer its jurisdictional amount, totaling $15 million, and amortize it over a five-year period. However, the NCUC order directed that amortization begin in the fourth quarter of 2006, with an amortization expense of $3 million. As a result, during the fourth quarter of 2006, PEC reversed $18 million of O&M expense, established a regulatory asset and recorded $3 million of amortization expense.

As discussed in Note 21B, PEC reclassified $29 million of expense from other, net to depreciation and amortization expense on the Consolidated Statements of Income for Clean Smokestacks Act amortization recognized during 2006.

The NCUC and SCPSC have approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The aggregate minimum and maximum amounts of cost recovery are $530 million and $750 million, respectively. Accelerated cost recovery of these assets resulted in no additional expense in 2006, 2005 or 2004. Through December 31, 2006, PEC recorded total accelerated depreciation of $403 million.

C. PEF Retail Rate Matters

BASE RATE AGREEMENT

As a result of a base rate proceeding in 2005, PEF is party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and will remain in effect through the last billing cycle of December 2009, with PEF having sole option to extend the agreement through the last billing cycle of June 2010. Additionally, PEF will continue to recover and collect a return on Hines Unit 2 through the fuel clause through late 2007, when it will be transferred into base rates. This transfer will correspond with the in-service dates of Hines Unit 4, which will also be recovered through a base rate increase. The settlement agreement also provides for revenue sharing between PEF and its ratepayers beginning in 2006 whereby PEF will refund two-thirds of retail base revenues between the specified threshold and specified cap and 100 percent of revenues above the specified cap. However, PEF's retail base revenues did not exceed the specified 2006 threshold of $1.499 billion and thus no revenues were subject to revenue sharing. Both the 2006 base threshold of $1.499 billion and the 2006 cap of $1.549 billion will be adjusted annually for rolling average 10-year retail kWh sales growth. The settlement agreement provides for PEF to continue to recover certain costs through clauses, such as the recovery of post-9/11 security costs through the capacity clause and the carrying costs of coal inventory in transit and coal procurement costs through the fuel clause. Under the settlement agreement, PEF is authorized to include an adjustment to increase common equity for the impact of Standard & Poor's Rating Services' (S&P's) imputed off-balance sheet debt for future capacity payments to qualifying facilities (QFs) and other entities under long-term purchase power agreements. This adjusted capital structure will be used for surveillance reporting with the FPSC and pass-through clause return calculations. PEF will use an authorized 11.75 percent return on equity (ROE) for cost-recovery clauses and AFUDC. In addition, PEF's adjusted equity ratio will be capped at 57.83 percent as calculated on a financial capital structure that includes the adjustment for the S&P imputed off-balance sheet debt. If PEF's regulatory ROE falls below 10 percent, and for certain other events, PEF is authorized to petition the FPSC for a base rate increase.

PASS-THROUGH CLAUSE COST RECOVERY

On September 1 and September 15, 2006, PEF filed requests with the FPSC seeking increases to cover rising fuel, environmental compliance and energy conservation costs. PEF asked the FPSC to approve a $171 million, or 3.7 percent, increase in rates. Subsequently, on October 25 and October 31, 2006, PEF supplemented its September filings to reflect lower projected fuel costs for PEF. PEF's revised forecasts resulted in a $40 million, or 0.7 percent, increase in rates over 2006. On November 8, 2006, the FPSC approved PEF's supplemental filing. The new charges were effective January 1, 2007, and increased residential bills $0.78 for the first 1,000 kWh. At December 31, 2006, PEF was over-recovered in fuel and capacity costs by $63 million and under-recovered in environmental compliance by $14 million.

On August 10, 2006, Florida's Office of Public Counsel (OPC) filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers $143 million, plus interest, of alleged excessive past fuel recovery charges and sulfur dioxide (SO_2) allowance costs associated with PEF's purported failure to utilize the most economical sources of coal at Crystal River Unit 4 and Crystal River Unit 5 (CR4 and CR5) during the period 1996 to 2005. The OPC subsequently revised its claim to $135 million, plus interest. The OPC claims that although CR4 and CR5 were designed to burn a blend of coals, PEF failed to act to lower ratepayers' costs by purchasing the most economical blends of coal. During the period specified in the petition, PEF's costs recovered through fuel recovery clauses were annually reviewed for prudence and approval by the FPSC. On August 30, 2006, PEF filed a motion with the FPSC to dismiss the petition on the grounds that the OPC petition would require the FPSC to engage in retroactive ratemaking for rates previously approved under the fuel recovery clause. On September 13, 2006, the OPC filed a memorandum in opposition to PEF's motion to dismiss the petition. PEF's motion to dismiss was denied by the FPSC on December 19, 2006. A hearing on the matter has been scheduled by the FPSC for April 2, 2007. PEF believes that its coal procurement practices were prudent and that it has sound legal and factual arguments to successfully defend its position. We cannot predict the outcome of this matter.

On September 22, 2006, PEF filed a petition with the FPSC for Determination of Need to uprate CR3, bid rule exemption and recovery of the costs through PEF's fuel recovery clause. The uprate will increase CR3's gross output by approximately 180 MW. The uprate will take place in two stages: approximately 40 MW will be added through equipment modifications during the 2009 refueling outage and approximately 140 MW will be added by modifying the design of the plant during the 2011 refueling outage to use more highly enriched fuel. The design modifications will require a license amendment approved by the NRC. The project is estimated to cost approximately $382 million, which includes potential transmission system improvements and modifications to comply with environmental regulations. The costs may continue to change depending upon the results of more detailed engineering and development work and increased material, labor and equipment costs. On February 8, 2007, the FPSC issued an order approving the need certification petition and bid rule exemption. The request for recovery of uprate costs through PEF's fuel recovery clause was transferred to a separate docket filed on January 16, 2007. The FPSC has scheduled a hearing to be held May 23, 2007, to determine whether the uprate costs should be recovered through the fuel adjustment clause. If PEF does not receive approval to recover the uprate costs through the fuel adjustment clause, these costs will be recoverable through base rates, similar to other utility plant additions. On February 2, 2007, intervenors filed a motion to abate the cost-recovery portion of PEF's request. On February 9, 2007, PEF requested that the FPSC deny the intervenors' motion as legally deficient and without merit. We cannot predict the outcome of this matter.

STORM COST RECOVERY

On July 14, 2005, the FPSC issued an order authorizing PEF to recover $232 million over a two-year period, including interest, of the costs it incurred and previously deferred related to PEF's restoration of power associated with the four hurricanes in 2004. The ruling allowed PEF to include a charge of approximately $3.27 on the average residential monthly customer bill of 1,000 kWh beginning August 1, 2005. The ruling by the FPSC approved the majority of PEF's requests with two exceptions: the reclassification of $8 million of previously deferred costs to utility plant and the reclassification of $17 million of previously deferred costs as O&M expense, which was expensed in the second quarter of 2005. The amount included in the original November 2004 petition requesting recovery of $252 million was an estimate. On September 12, 2005, PEF filed a true-up to the original amount comprised primarily of an additional $19 million of costs partially offset by $6 million of adjustments resulting from allocating a higher portion of the costs to the wholesale jurisdiction and refining the FPSC adjustments On November 9, 2005, the recovery of this difference was administratively approved by the FPSC, subject to audit by the FPSC staff. The net impact was included in customer bills beginning January 1, 2006. In 2006 and 2005, PEF recorded amortization of $122 million and $50 million, respectively, associated with the recovery of these storm costs

On April 25, 2006, PEF entered into a settlement agreement with certain intervenors in its storm cost-recovery docket that would allow PEF to extend its current two-year storm surcharge, which equals approximately $3.61 on the average residential monthly customer bill of 1,000 kWh, for an additional 12-month period to replenish its storm reserve. The requested extension, which would begin August 2007, would replenish the existing storm reserve by an estimated additional $130 million. During the third quarter of 2006, PEF and the intervenors modified the settlement agreement such that in the event future storms deplete the reserve, PEF would be able to petition the FPSC for implementation of an interim surcharge of at least 80 percent and up to 100 percent of the claimed deficiency of its storm reserve. The intervenors agreed not to oppose the interim recovery of 80 percent of the future claimed deficiency but reserved the right to challenge the interim surcharge recovery of the remaining 20 percent The FPSC has the right to review PEF's storm costs for prudence. On August 29, 2006, the FPSC approved the settlement agreement as modified.

FRANCHISE MATTERS

On June 1, 2005, Winter Park acquired PEF's electric distribution system that serves Winter Park for approximately $42 million. On June 1, 2005, PEF transferred the distribution system to Winter Park and recognized a pre-tax gain of approximately $25 million on the transaction, which is included as an offset to other utility expense on the Statements of Income. This amount was decreased $1 million in the third quarter of 2005 upon accumulation of the final capital expenditures incurred since arbitration PEF also recorded a regulatory liability of $8 million for stranded cost revenues, which will be amortized to revenues over six years in accordance with the provisions of the transfer agreement with Winter Park In June 2004, Winter Park executed a wholesale power supply contract with PEF with a five-year term and a renewal option

OTHER MATTERS

On November 3, 2004, the FPSC approved PEF's petition for Determination of Need for the construction of a fourth unit at PEF's Hines Energy Complex Hines Unit 4 is needed to maintain electric system reliability and integrity and to continue to provide adequate electricity to its ratepayers at a reasonable cost The unit is planned for commercial operation in December 2007 Hines Unit 4 will be a combined cycle unit with a generating capacity of 461 MW (summer rating) The estimated total in-service cost of Hines Unit 4 approved as part of the Determination of Need was $286 million If the actual cost is less than the original estimate, ratepayers will receive the benefit of such cost under-runs. Any costs that exceed this estimate will not be recoverable absent, among other things, extraordinary circumstances as found by the FPSC in subsequent proceedings. The current estimate of in-service cost exceeds the initial project estimate by approximately 12 percent to 15 percent due to what we believe to be extraordinary circumstances. Therefore, we believe that disallowance of these costs by the FPSC in subsequent proceedings is not probable. We cannot predict the outcome of this matter

D. Regional Transmission Organizations

In 2000, the FERC issued Order 2000, which set minimum characteristics and functions that regional transmission organizations (RTOs) must meet, including independent transmission service In October 2000, as a result of Order 2000, PEC, along with Duke Energy Corporation and South Carolina Electric & Gas Company, filed an application with the FERC for approval of an RTO, GridSouth. In July 2001, the FERC issued an order provisionally approving GridSouth However, in July 2001, the FERC issued orders recommending that companies in the southeastern United States engage in mediation to develop a plan for a single RTO PEC participated in the mediation; no consensus was reached on creating a Southeast RTO. On August 11, 2005, the GridSouth participants notified the FERC that they had terminated the GridSouth project. By order issued October 20, 2005, the FERC terminated the GridSouth proceeding. PEC's investment in GridSouth totaled $33 million at December 31, 2006 and 2005 PEC expects to recover its investment.

PEF was one of three major investor-owned Florida utilities that formed the GridFlorida RTO in 2000. A cost-benefit study conducted during 2005 concluded that the GridFlorida RTO was not cost effective for FPSC jurisdictional customers and shifted benefits to nonjurisdictional customers. In light of these findings, during 2006 the FPSC and the FERC closed their respective docketed proceedings and GridFlorida was dissolved PEF fully recovered its startup costs in GridFlorida from retail ratepayers through base rates.

E. Nuclear License Renewals

On June 26, 2006, Brunswick received 20-year extensions from the NRC on the operating licenses for its two nuclear reactors. The operating licenses have been extended to 2036 for Unit No. 1 and 2034 for Unit No. 2. On November 14, 2006, PEC filed an application for a 20-year extension from the NRC on the operating license for Harris, which would extend the operating license through 2046, if approved.

F. FERC Market Power Mitigation

In April 2004, the FERC issued two orders concerning utilities' ability to sell wholesale electricity at market-based rates. In the first order, the FERC adopted two interim screens for assessing potential generation market power of applicants for wholesale market-based rates, and described additional analyses and mitigation measures that could be presented if an applicant did not pass one of the interim screens. In July 2004, the FERC issued an order on rehearing affirming its conclusions in the April order. In the second order, the FERC initiated a rulemaking to consider whether the FERC's current methodology for determining whether a public utility should be allowed to sell wholesale electricity at market-based rates should be modified in any way. PEF does not have market-based rate authority for wholesale sales in peninsular Florida. Given the difficulty PEC believed it would experience in passing one of the interim screens, on September 6, 2005, PEC filed revisions to its market-based rate tariffs restricting them to sales outside PEC's control area and peninsular Florida and a new cost-based tariff for sales within PEC's control area. The FERC has accepted these revised tariffs.

8. GOODWILL AND OTHER INTANGIBLE ASSETS

We perform annual goodwill impairment tests in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Goodwill was tested for impairment for both the PEC and PEF segments in the second quarters of 2005 and 2006; each test indicated no impairment. Under SFAS No. 142, all goodwill is assigned to our reporting units that are expected to benefit from the synergies of the business combination.

Included in the assets of discontinued operations at December 31, 2005, is the goodwill related to CCO. For CCO, the goodwill impairment tests were performed at the reporting unit level of our Effingham, Monroe, Walton and Washington nonregulated generating plants (Georgia Region), which is one level below CCO. As a result of our evaluation of certain business opportunities that impacted the future cash flows of our Georgia Region operations, we performed an interim goodwill impairment test during the first quarter of 2006. We estimated the fair value of that reporting unit using the expected present value of future cash flows. As a result of that test, we recognized a pre-tax goodwill impairment charge of $64 million ($39 million after-tax) during the first quarter of 2006, which was previously reported within impairment of assets on the Consolidated Statements of Income. This impairment was reclassed to discontinued operations on the Consolidated Statements of Income during the fourth quarter of 2006 (See Note 3A).

The gross carrying amount and accumulated amortization of the intangible assets at December 31 were as follows:

	2006		2005	
(in millions)	**Gross Carrying Amount**	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
Synthetic fuels intangibles	**$107**	**$(107)**	$134	$(98)
Other	**6**	**(6)**	29	(6)
Total	**$113**	**$(113)**	$163	$(104)

All of our intangibles, except minimum pension liability adjustments, are subject to amortization. Synthetic fuels intangibles represent intangibles for synthetic fuels technology. Other intangibles are primarily acquired customer contracts, permits that are amortized over their respective lives and minimum pension liability adjustments.

Amortization expense recorded on intangible assets was $9 million for the year ended December 31, 2006, and $19 million for both years ended December 31, 2005 and 2004. No annual amortization expense for intangible assets is expected for 2007 through 2011.

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding future synthetic fuels production. With the idling of these facilities, we performed an evaluation of the intangible assets, which were comprised primarily of capitalized acquisition costs (See Note 9 for impairment of related long-lived assets). The impairment test considered numerous factors including, among other things, continued high oil prices and the then-current "idle" state of our synthetic fuels facilities We estimated the fair value using the expected present value of future cash flows Based on the results of the impairment test, we recorded a pre-tax impairment charge of $27 million ($17 million after-tax) during the quarter ended June 30, 2006, which is reported within impairment of assets on the Consolidated Statements of Income. This charge represents the entirety of the synthetic fuels intangible assets; these assets had been reported within the Coal and Synthetic Fuels segment Following a significant decrease in oil prices, our synthetic fuels facilities resumed limited production of synthetic fuels in September and October 2006, which continued through the end of 2006.

9. IMPAIRMENTS OF LONG-LIVED ASSETS AND INVESTMENTS

We apply SFAS No. 144 for the accounting and reporting of impairment or disposal of long-lived assets In 2006 and 2005, we recorded pre-tax long-lived asset and investment impairments and other charges of $65 million and $1 million, respectively. No impairments were recorded in 2004.

A. Long-Lived Assets

Due to rising current and future oil prices, in the third and fourth quarters of 2005 we tested our synthetic fuels plant assets for impairment. These tests indicated that the assets were recoverable and no impairment charge was recorded See Note 22D for additional information.

Concurrent with the synthetic fuels intangibles impairment evaluation discussed in Note 8, we also performed an impairment evaluation of related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded a pre-tax impairment charge of $64 million ($38 million after-tax) during the quarter ended June 30, 2006, which is reported within impairment of assets on the Consolidated Statements of Income. This charge represents the entirety of the asset carrying value of our synthetic fuels manufacturing facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels manufacturing facilities are located. These assets had been reported within the Coal and Synthetic Fuels segment. As discussed in Note 8, our synthetic fuels facilities resumed limited production of synthetic fuels in September and October 2006, which continued through the end of 2006

B. Investments

We evaluate declines in value of investments under the criteria of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115), and FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairments and Its Application to Certain Investments" (See Note 1D). Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts and other available-for-sale securities. See Note 13 for additional information

We continually review PEC's affordable housing investment (AHI) portfolio for impairment. As a result of various factors, including continued operating losses of the AHI portfolio and management issues arising at certain properties within the AHI portfolio, we recorded impairment charges of $1 million on a pre-tax basis in both 2006 and 2005. No impairments were recorded in 2004

10. EQUITY

A. Common Stock

At December 31, 2006 and 2005, we had 500 million shares of common stock authorized under our charter, of which 256 million shares and 252 million shares, respectively, were outstanding. During 2006, 2005 and 2004, respectively, we issued approximately 4.2 million, 4.8 million and 1.7 million shares of common stock, resulting in approximately $185 million, $208 million and $73 million in proceeds. Included in these amounts for 2006, 2005 and 2004, respectively, were approximately 1.6 million, 4.6 million and 1.4 million shares for proceeds of approximately $70 million, $199 million and $62 million, to meet the requirements of the Progress Energy 401(k) Savings and Stock Ownership Plan (401(k)) and the Investor Plus Stock Purchase Plan

At December 31, 2006 and 2005, we had approximately 54 million shares and 58 million shares, respectively, of common stock authorized by the board of directors that remained unissued and reserved, primarily to satisfy the requirements of our stock plans. In 2002, the board of directors authorized meeting the requirements of the 401(k) and the Investor Plus Stock Purchase Plan with original issue shares. We continue to meet the requirements of the restricted stock plan with issued and outstanding shares.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2006, there were no significant restrictions on the use of retained earnings (See Note 12).

B. Stock-Based Compensation

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. At December 31, 2006 and 2005, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has matching and incentive goal features, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan is held by the 401(k) Trustee in a suspense account. The common stock is released from the suspense account and made available for allocation to participants as the ESOP loan is repaid. Such allocations are used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes.

There were 2.3 million and 2.9 million ESOP suspense shares at December 31, 2006 and 2005, respectively, with a fair value of $112 million and $126 million, respectively. ESOP shares allocated to plan participants totaled 10.9 million and 11.4 million at December 31, 2006 and 2005, respectively. Our matching and incentive goal compensation cost under the 401(k) is determined based on matching percentages and incentive goal attainment as defined in the plan. Such compensation cost is allocated to participants' accounts in the form of Progress Energy common stock, with the number of shares determined by dividing compensation cost by the common stock market value at the time of allocation. We currently meet common stock share needs with open market purchases, with shares released from the ESOP suspense account and with newly issued shares. Costs for incentive goal compensation are accrued during the fiscal year and typically paid in shares in the following year, while costs for the matching component are typically met with shares in the same year incurred. Matching and incentive costs, which were met and will be met with shares released from the suspense account, totaled approximately $14 million, $18 million and $21 million for the years ended December 31, 2006, 2005 and 2004, respectively. Total matching and incentive costs were approximately $23 million, $30 million and $32 million for the years ended December 31, 2006, 2005 and 2004, respectively. We have a long-term note receivable from the 401(k) Trustee related to the purchase of common stock from us in 1989. The balance of the note receivable from the 401(k) Trustee is included in the determination of unearned ESOP common stock, which reduces common stock equity. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. Interest income on the note receivable and dividends on unallocated ESOP shares are not recognized for financial statement purposes.

STOCK OPTIONS

Pursuant to our 1997 Equity Incentive Plan and 2002 Equity Incentive Plan, amended and restated as of July 10, 2002, we may grant options to purchase shares of Progress Energy common stock to directors, officers and eligible employees for up to 5 million and 15 million shares, respectively. Generally, options granted to employees vest one-third per year with 100 percent vesting at the end of year three, while options granted to directors vest 100 percent at the end of one year. The options expire 10 years from the date of grant. All option grants have an exercise price equal to the fair market value of our common stock on the grant date. We curtailed our stock option program in 2004 and replaced that compensation program with other programs. An immaterial number of stock options were granted in 2004 and no stock options have been granted in 2005 or 2006. We issue new shares of common stock to satisfy the exercise of previously issued stock options.

A summary of the status of our stock options at December 31, 2006, and changes during the year then ended, follows.

(option quantities in millions)	Number of Options	Weighted-Average Exercise Price
Options outstanding, January 1	7.0	$43.58
Granted	–	–
Forfeited	(0.1)	44.75
Canceled	(0.2)	43.74
Exercised	(2.7)	43.37
Options outstanding, December 31	4.0	43.70
Options exercisable, December 31	4.0	43.70

The options outstanding and exercisable at December 31, 2006, had a weighted-average remaining contractual life of 5.8 years and an aggregate intrinsic value of $22 million. Total intrinsic value of options exercised during the year ended December 31, 2006, was $10 million. Total intrinsic value of options exercised during the year ended December 31, 2005, was less than $1 million. The total intrinsic value of options exercised during the year ended December 31, 2004, was $1 million.

Compensation cost, for pro forma purposes prior to the adoption of SFAS No. 123R and for expense purposes subsequent to the adoption, is measured at the grant date based on the fair value of the award and is recognized over the vesting period. The fair value for these options was estimated at the grant date using a Black-Scholes option pricing model with the following weighted-average assumptions:

	2004
Risk-free interest rate	4.22%
Dividend yield	5.19%
Volatility factor	20.30%
Weighted-average expected life of the options (in years)	10

Dividend yield and the volatility factor were calculated using three years of historical trend information. The expected term was based on the contractual life of the options.

Stock option expense totaling $2 million was recognized in income during the year ended December 31, 2006, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year. Stock option expense totaling $3 million was recognized in income during the year ended December 31, 2005, with a recognized tax benefit of $1 million. No compensation cost related to stock options was capitalized during the year.

As previously indicated, we did not record stock option expense prior to the adoption of SFAS No. 123R as of July 1, 2005. The following table illustrates the effect on our net income and earnings per share if the fair value method had been applied to all outstanding and nonvested awards in each period:

(in millions, except per share data)	2005	2004
Net income, as reported	$697	$759
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	2	10
Pro forma net income	$695	$749
Earnings per share		
Basic – as reported	$2.82	$3.13
Basic – pro forma	2.81	3.09
Diluted – as reported	2.82	3.12
Diluted – pro forma	2.81	3.08

As of December 31, 2006, all options were fully vested and no compensation expense related to stock options is expected in future periods.

Cash received from the exercise of stock options totaled $115 million, $8 million and $18 million, respectively, during the years ended December 31, 2006, 2005 and 2004. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2006, was $4 million. The actual tax benefit for tax deductions from stock option exercises for the years ended December 31, 2005 and 2004 was not significant.

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. The two primary active stock-based compensation programs are the Performance Share Sub-Plan (PSSP) and the Restricted Stock Awards (RSA) program, both of which were established pursuant to our 1997 Equity Incentive Plan and were continued under our 2002 Equity Incentive Plan, as amended and restated from time to time.

We granted cash-settled PSSP awards prior to 2005. Beginning in 2005, we are granting stock-settled PSSP awards. Under the terms of the cash-settled PSSP, our officers and key employees are granted a target number of performance shares on an annual basis that vest over a three-year consecutive period. Each performance share has a value that is equal to, and changes with, the value of a share of Progress Energy common stock, and dividend equivalents are accrued on, and reinvested in, the performance shares. The PSSP has two equally weighted performance measures, both of which are based on our results as compared to a peer group of utilities. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. Compensation expense is recognized over the vesting period based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. The stock-settled PSSP is similar to the cash-settled PSSP, except that we distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with certain subsequent adjustments related to our results as compared to the peer group of utilities. PSSP cash-settled liabilities totaling $4 million, $5 million and $7 million were paid in the years ended December 31, 2006, 2005 and 2004, respectively. A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2006, and changes during the year then ended is presented below:

	Number of Stock-Settled Performance Shares[a]	Weighted-Average Grant Date Fair Value
Beginning balance	540,588	$44.24
Granted	556,431	44.27
Paid	(54)	44.27
Vested	–	–
Forfeited	(52,382)	44.25
Ending balance	1,044,583	$44.26

[a] Amounts reflect target shares to be issued. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

For the year ended December 31, 2005, the weighted-average grant date fair value of stock-settled performance shares granted was $44.24.

The RSA program allows us to grant shares of restricted common stock to our officers and key employees. The restricted shares generally vest on a graded vesting schedule over a minimum of three years. Compensation expense, which is based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. Restricted shares are not included as shares outstanding in the basic earnings per share calculation until the shares are no longer forfeitable. A summary of the status of the nonvested restricted stock shares at December 31, 2006, and changes during the year then ended, is presented below:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	588,308	$43.27
Granted	168,800	44.51
Vested	(102,836)	41.87
Forfeited	(50,034)	43.68
Ending balance	604,238	$43.82

For the years ended December 31, 2005 and 2004, the weighted-average grant date fair value of restricted stock granted was $42.56 and $46.95, respectively.

The total fair value of restricted stock vested during the years ended December 31, 2006, 2005 and 2004 was $4 million, $7 million and $16 million, respectively. Cash expended to purchase shares for the restricted stock program totaled $8 million, $8 million and $7 million during the years ended December 31, 2006, 2005 and 2004, respectively.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $25 million for the year ended December 31, 2006, with a recognized tax benefit of $10 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $10 million, with a recognized tax benefit of $4 million, for each of the years ended December 31, 2005 and 2004. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2006, there was $33 million of total unrecognized compensation cost related to nonvested other stock-based compensation plan awards, which is expected to be recognized over a weighted-average period of 2.1 years.

C. Earnings Per Common Share

Basic earnings per common share are based on the weighted-average number of common shares outstanding. Diluted earnings per share include the effect of the nonvested portion of restricted stock awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for the years ended December 31 for basic and dilutive purposes follows:

(in millions)	2006	2005	2004
Weighted-average common shares – basic	250.4	246.6	242.2
Net effect of dilutive stock-based compensation plans	0.4	0.4	0.9
Weighted-average shares – fully diluted	250.8	247.0	243.1

There were no adjustments to net income or to income from continuing operations between the calculations of basic and fully diluted earnings per common share. ESOP shares that have not been committed to be released to participants' accounts are not considered outstanding for the determination of earnings per common share. The weighted-average shares totaled 2.4 million, 3.0 million and 3.6 million for the years ended December 31, 2006, 2005 and 2004, respectively. There were 1.8 million, 2.9 million and 3.0 million stock options outstanding at December 31, 2006, 2005 and 2004, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive.

D. Accumulated Other Comprehensive Loss

Components of accumulated other comprehensive loss, net of tax, at December 31 were as follows:

(in millions)	2006	2005
(Loss) gain on cash flow hedges	$(14)	$55
Minimum pension liability adjustments	–	(160)
SFAS No. 158 benefits adjustment	(39)	–
Other	4	1
Total accumulated other comprehensive loss	$(49)	$(104)

11. PREFERRED STOCK OF SUBSIDIARIES – NOT SUBJECT TO MANDATORY REDEMPTION

All of our preferred stock was issued by our subsidiaries and was not subject to mandatory redemption. At December 31, 2006 and 2005, preferred stock outstanding consisted of the following:

	Shares			
(dollars in millions, except share and per share data)	Authorized	Outstanding	Redemption Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000			
$5 Preferred		236,997	$110.00	$24
Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	–	–	–
No par value Preference Stock	10,000,000	–	–	–
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	–	–	–
$100 par value Preference Stock	1,000,000	–	–	–
Total PEF				34
Total preferred stock of subsidiaries				$93

12. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2006):

(in millions)		**2006**	2005
Progress Energy, Inc.			
Senior unsecured notes, maturing 2010-2031	6.98%	**$2,600**	$4,300
Unamortized fair value hedge gain, net		**(1)**	(3)
Unamortized premium and discount, net		**(18)**	(19)
Current portion of long-term debt		**–**	(404)
Long-term debt, net		**2,581**	3,874
PEC			
First mortgage bonds, maturing 2007-2033	5.76%	**2,200**	2,200
Pollution control obligations, maturing 2017-2024	3.74%	**669**	669
Senior unsecured notes, maturing 2012	6.50%	**500**	500
Medium-term notes, maturing 2008	6.65%	**300**	300
Miscellaneous notes		**22**	22
Unamortized premium and discount, net		**(21)**	(24)
Current portion of long-term debt		**(200)**	–
Long-term debt, net		**3,470**	3,667
PEF			
First mortgage bonds, maturing 2008-2033	5.39%	**1,630**	1,630
Pollution control obligations, maturing 2018-2027	3.66%	**241**	241
Senior unsecured notes, maturing 2008	5.77%	**450**	450
Medium-term notes, maturing 2007-2028	6.77%	**241**	289
Unamortized premium and discount, net		**(5)**	(8)
Current portion of long-term debt		**(89)**	(48)
Long-term debt, net		**2,468**	2,554
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	**309**	309
Unamortized premium and discount, net		**(38)**	(39)
Long-term debt, net		**271**	270
Progress Capital Holdings, Inc.			
Medium-term notes, maturing 2007-2008	6.59%	**80**	140
Miscellaneous notes		**–**	2
Current portion of long-term debt		**(35)**	(61)
Long-term debt, net		**45**	81
Consolidated long-term debt, net		**$8,835**	$10,446

At December 31, 2005, we classified $397 million, related to the retirement of $800 million in Progress Energy, Inc. 6.75% Senior Notes on March 1, 2006, as long-term debt. Settlement of this obligation was not expected to require the use of working capital in 2006 as we had the intent and ability to refinance this debt on a long-term basis.

On January 13, 2006, Progress Energy issued $300 million of 5.625% Senior Notes due 2016 and $100 million of Series A Floating Rate Senior Notes due 2010, receiving net proceeds of $397 million. These senior notes are unsecured. Interest on the Floating Rate Senior Notes is based on three-month London Inter Bank Offering Rate

(LIBOR) plus 45 basis points and resets quarterly. We used the net proceeds from the sale of these senior notes and a combination of available cash and commercial paper proceeds to retire the $800 million aggregate principal amount of our 6.75% Senior Notes on March 1, 2006. Pending the application of the proceeds described above, we invested the net proceeds in short-term, interest-bearing, investment-grade securities.

On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008, at a make-whole redemption price. The 6.05% Senior Notes were acquired at 100.274 percent of par, or approximately $351 million, plus accrued interest, and the 5.85% Senior Notes were acquired at 101.610 percent of par, or approximately $406 million, plus accrued interest. The redemptions were funded with available cash on hand and no additional debt was incurred in connection with the redemptions. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest. The redemption was funded with available cash on hand and no additional debt was incurred in connection with the redemption. See Note 20 for a discussion of losses on debt redemptions.

At December 31, 2006 and 2005, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2006 and 2005, we had no outstanding borrowings under our credit facilities. We are required to pay minimal annual commitment fees to maintain our credit facilities.

The following table summarizes our revolving credit agreements (RCAs) and available capacity at December 31, 2006:

In addition to the committed RCAs at December 31, 2005, we had an $800 million 364-day credit agreement, which was restricted for the retirement of $800 million of 6.75% Senior Notes due March 1, 2006. On March 1, 2006, Progress Energy, Inc. retired $800 million of its 6.75% Senior Notes, thus effectively terminating the 364-day credit agreement.

On May 3, 2006, Progress Energy restructured its existing $1.13 billion five-year RCA with a syndication of financial institutions. The new RCA replaced an existing $1.13 billion five-year facility, which was terminated effective May 3, 2006. The new RCA will continue to be used to provide liquidity support for Progress Energy's issuances of commercial paper and other short-term obligations. The new RCA no longer includes a material adverse change representation for borrowings or a financial covenant for interest coverage. Fees and interest rates under the new RCA will continue to be determined based upon the credit rating of Progress Energy's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa2 by Moody's Investors Service, Inc. (Moody's) and BBB- by S&P.

On May 3, 2006, PEC's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEC's long-term unsecured senior noncredit-enhanced debt, currently rated as Baa1 by Moody's and BBB- by S&P.

On May 3, 2006, PEF's five-year $450 million RCA was amended to take advantage of favorable market conditions and reduce the pricing associated with the facility. Fees and interest rates under the RCA will continue to be determined based upon the credit rating of PEF's long-term unsecured senior noncredit-enhanced debt, currently rated as A3 by Moody's and BBB- by S&P.

(in millions)	Description	Total	Outstanding	Reserved[a]	Available
Progress Energy, Inc.	Five-year (expiring 5/3/11)	$1,130	$–	$(60)	$1,070
PEC	Five-year (expiring 6/28/10)	450	–	–	450
PEF	Five-year (expiring 3/28/10)	450	–	–	450
Total credit facilities		$2,030	$–	$(60)	$1,970

[a] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2006, Progress Energy, Inc. had a total amount of $60 million of letters of credit issued, which were supported by the RCA.

We had no commercial paper outstanding or other short-term debt at December 31, 2006. The following table summarizes our outstanding commercial paper and other short-term debt and related weighted-average interest rates at December 31, 2005:

(in millions)		
PEC	4.65%	$73
PEF	4.75%	102
Total	4.71%	$175

The following table presents the aggregate maturities of long-term debt at December 31, 2006:

(in millions)	
2007	$324
2008	877
2009	400
2010	406
2011	1,000
Thereafter	6,235
Total	$9,242

B. Covenants and Default Provisions

FINANCIAL COVENANTS

Progress Energy, Inc.'s, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2006, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Progress Energy, Inc.	68%	55.4%
PEC	65%	52.3%
PEF	65%	49.4%

[a] Indebtedness as defined by the bank agreements includes certain letters of credit and guarantees that are not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for Progress Energy, Inc. and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. Progress Energy, Inc.'s cross-default provision applies only to Progress Energy, Inc. and its significant subsidiaries, as defined in the credit agreement (i.e., PEC, Florida Progress Corporation [Florida Progress], PEF, Progress Capital Holdings, Inc. and PVI). PEC's and PEF's cross-default provisions apply only to defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not each other or other affiliates of PEC and PEF.

Additionally, certain of Progress Energy, Inc.'s long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of Progress Energy, Inc., primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $2.6 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither Progress Energy, Inc.'s Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2006, Progress Energy, Inc. had no shares of preferred stock outstanding. Certain documents restrict the payment of dividends by Progress Energy, Inc.'s subsidiaries as outlined below.

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2006, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below

25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2006, PEC's common stock equity was approximately 49.0 percent of total capitalization. At December 31, 2006, none of PEC's cash dividends or distributions on common stock was restricted.

PEF's mortgage indenture provides that so long as any first mortgage bonds are outstanding, it will not pay any cash dividends upon its common stock, or make any other distribution to the stockholders, except a payment or distribution out of net income of PEF subsequent to December 31, 1943. At December 31, 2006, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2006, PEF's common stock equity was approximately 51.8 percent of total capitalization. At December 31, 2006, none of PEF's cash dividends or distributions on common stock was restricted.

C. Collateralized Obligations

PEC's and PEF's first mortgage bonds are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2006, PEC and PEF had a total of $2.869 billion and $1.871 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

See Note 18 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. Hedging Activities

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See Note 17 for a discussion of risk management activities and derivative transactions.

13. INVESTMENTS AND FAIR VALUE OF FINANCIAL INSTRUMENTS

A. Investments

At December 31, 2006 and 2005, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

(in millions)	**2006**	2005
Nuclear decommissioning trust (See Note 5D)	**$1,287**	$1,133
Investments in equity securities[a]	**6**	7
Equity method investments[b]	**23**	27
Cost investments[c]	**8**	13
Benefit investment trusts[d]	**80**	77
Company-owned life insurance[d]	**161**	153
Marketable debt securities[e]	**71**	191
Total	**$1,636**	$1,601

[a] Certain investments in equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115 (See Note 1). These investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets.
[b] Investments in unconsolidated companies are included in the Consolidated Balance Sheets in miscellaneous other property and investments using the equity method of accounting (See Note 1). These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis (See Note 20).
[c] Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.
[d] Investments in company-owned life insurance and other benefit plan assets are included in miscellaneous other property and investments in the Consolidated Balance Sheets and approximate fair value due to the short maturity of the instruments.
[e] We actively invest available cash balances in various financial instruments, such as tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through arrangements with banks that provide daily and weekly liquidity and 7-, 28- and 35-day auctions that allow for the redemption of the investment at its face amount plus earned income. As we intend to sell these instruments within one year or less, generally within 30 days, from the balance sheet date, they are classified as short-term investments.

B. Fair Value of Financial Instruments

DEBT

The carrying amount of our long-term debt, including current maturities, was $9.159 billion and $10.959 billion at December 31, 2006 and 2005, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $9.543 billion and $11.491 billion at December 31, 2006 and 2005, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values, and for which we do not have control, are accounted for as available-for-sale securities at fair value in accordance with SFAS No. 115. These investments include investments held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning nuclear plants (See Note 5D). These nuclear decommissioning trust funds are primarily invested in stocks, bonds and cash equivalents that are classified as available-for-sale. Nuclear decommissioning trust funds are presented on the Consolidated Balance Sheets at amounts that approximate fair value. Fair value is obtained from quoted market prices for the same or similar investments. In addition to the nuclear decommissioning trust funds, we hold other debt and equity investments classified as available-for-sale in miscellaneous other property and investments on the Consolidated Balance Sheets at amounts that approximate fair value. Our available-for-sale securities at December 31, 2006 and 2005 are summarized below. Net nuclear decommissioning trust fund unrealized gains are included in regulatory liabilities (See Note 7A).

2006 *(in millions)*	**Book Value**	**Unrealized Gains**	**Estimated Fair Value**
Equity securities	**$428**	**$324**	**$752**
Debt securities	**606**	**13**	**619**
Cash equivalents	**19**	**–**	**19**
Total	**$1,053**	**$337**	**$1,390**
2005 *(in millions)*	Book Value	Unrealized Gains	Estimated Fair Value
Equity securities	$406	$257	$663
Debt securities	673	7	680
Cash equivalents	18	–	18
Total	$1,097	$264	$1,361

At December 31, 2006, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$28
Due after one through five years	116
Due after five through 10 years	196
Due after 10 years	279
Total	$619

Selected information about our sales of available-for-sale securities during the years ended December 31 is presented below. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2006**	2005	2004
Proceeds	**$2,547**	$3,755	$3,200
Realized gains	**33**	26	55
Realized losses	**24**	31	31

The NRC requires nuclear decommissioning trusts to be managed by third-party investment managers who have a right to sell securities without our authorization. Therefore, we consider available-for-sale securities in our nuclear decommissioning trust funds to be impaired if they are in a loss position. These impairments along with unrealized gains are included in our regulatory liabilities (See Note 7A) and have no earnings impact. Some of our benefit investment trusts are also managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2006 and 2005 for investments in these trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2006 and 2005 our other securities had no investments in a continuous loss position for greater than 12 months.

14. INCOME TAXES

We provide deferred income taxes for temporary differences. These occur when there are differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes under SFAS No. 109 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to SFAS No. 71. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders.

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	2006	2005
Deferred income tax assets		
Asset retirement obligation liability	$141	$155
Compensation accruals	99	99
Deferred revenue	28	55
Derivative instruments	42	–
Environmental remediation liability	36	27
Income taxes refundable through future rates	216	234
Investments	5	–
SFAS No. 158, postretirement and pension benefits	351	274
Unbilled revenue	36	30
Other	125	108
Federal income tax credit carry forward	851	957
State net operating loss carry forward (net of federal expense)	54	44
Valuation allowance	(71)	(39)
Total deferred income tax assets	1,913	1,944
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(1,349)	(1,396)
Deferred fuel recovery	(60)	(89)
Deferred storm costs	(51)	(94)
Derivative instruments	–	(32)
Income taxes recoverable through future rates	(436)	(202)
Investments	–	(35)
Other	(70)	(64)
Total deferred income tax liabilities	(1,966)	(1,912)
Total net deferred income tax (liabilities) assets	$(53)	$32

The above amounts were classified in the Consolidated Balance Sheets as follows:

(in millions)	2006	2005
Current deferred income tax assets	$159	$37
Noncurrent deferred income tax assets, included in other assets and deferred debits	19	79
Current deferred income tax liabilities, included in other current liabilities	(1)	(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(230)	(83)
Total net deferred income tax (liabilities) assets	$(53)	$32

At December 31, 2006 and 2005, we had recorded $76 million and $115 million, respectively, related to probable tax liabilities associated with prior filings, excluding accrued interest and penalties, which were included in noncurrent income tax liabilities on the Consolidated Balance Sheets.

At December 31, 2006, the federal income tax credit carry forward includes $850 million of alternative minimum tax credits that do not expire and $1 million of general business credits that will expire during the period 2023 through 2025.

At December 31, 2006, we had gross state net operating loss carry forwards of $1.1 billion that will expire during the period 2009 through 2026.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We established additional valuation allowances of $32 million during 2006. We believe it is more likely than not that the results of future operations will generate sufficient taxable income to allow for the utilization of the remaining deferred tax assets.

We establish accruals for certain tax contingencies when, despite our belief that our tax return positions are fully supported, we believe that certain positions may be challenged and that it is probable our positions may not be fully sustained. We are under continuous examination by the IRS and other tax authorities, and we account for potential losses of tax benefits in accordance with SFAS No. 5. At December 31, 2006 and 2005, we had recorded $27 million and $60 million, respectively, of tax contingency reserves, excluding accrued interest and penalties, which were included in taxes accrued on the Consolidated Balance Sheets.

Considering all tax contingency reserves, we do not expect the resolution of these matters to have a material impact on our financial position or results of operations. The tax contingency reserves relate primarily to capitalization and basis issues.

Reconciliations of our effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2006	2005	2004
Effective income tax rate	28.1%	(5.9)%	9.3%
State income taxes, net of federal benefit	(6.5)	(3.7)	(7.7)
Minority interest	0.2	(2.3)	(1.2)
Federal tax credits	11.3	43.7	30.2
Investment tax credit amortization	1.7	2.0	1.9
Employee stock ownership plan dividends	1.7	1.9	2.1
Domestic manufacturing deduction	0.5	1.3	–
Other differences, net	(2.0)	(2.0)	0.4
Statutory federal income tax rate	35.0%	35.0%	35.0%

Our effective income tax rate is favorably impacted by federal tax credits resulting from synthetic fuels production.

Income tax expense (benefit) applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	2006	2005	2004
Current – federal	$377	$382	$249
– state	69	78	71
Deferred – federal	(136)	(163)	(33)
– state	(26)	(36)	10
Valuation allowance	14	–	–
State net operating loss carry forward	(3)	(3)	(1)
Synthetic fuels tax credit	(79)	(282)	(215)
Investment tax credit	(12)	(13)	(14)
Total income tax expense (benefit)	$204	$(37)	$67

Total income tax expense (benefit) applicable to continuing operations excluded the following:

- Less than $1 million of deferred tax expense related to the cumulative effect of changes in accounting principle recorded net of tax during 2005. There was no cumulative effect of changes in accounting principle recorded during 2006 or 2004.
- Taxes related to discontinued operations recorded net of tax for 2006, 2005 and 2004, which are presented separately in Notes 3A through 3G
- Taxes related to other comprehensive income recorded net of tax for 2006, 2005 and 2004, which are presented separately in the Consolidated Statements of Comprehensive Income
- Current tax benefit of $3 million related to excess tax deductions resulting from vesting of restricted stock, interim period vesting of stock-settled PSSP awards and exercises of nonqualified stock options, which was recorded in common stock during 2006. Current tax benefit of $2 million related to excess tax deductions resulting from vesting of restricted stock and exercises of nonqualified stock options, which was recorded in common stock during 2005. Less than $1 million was recorded in common stock for excess tax deductions during 2004.

Through our subsidiaries, we are a majority owner in five entities and a minority owner in one entity that own facilities that produce synthetic fuels as defined under the Code. The production and sale of the synthetic fuels from these facilities qualifies for tax credits under Section 29/45K, if certain requirements are satisfied.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million contingent value obligations (CVOs). Each CVO represents the right of the holder to receive contingent payments based on the performance of four synthetic fuels facilities purchased by subsidiaries of Florida Progress in October 1999. The payments, if any, would be based on the net after-tax cash flows the facilities generate. The CVO liability is adjusted to reflect market price fluctuations. The unrealized loss/gain recognized due to these market fluctuations is recorded in other, net on the Consolidated Statements of Income (See Note 20). The liability, included in other liabilities and deferred credits on the Consolidated Balance Sheets, at December 31, 2006 and 2005, was $32 million and $7 million, respectively.

16. BENEFIT PLANS

A. Postretirement Benefits

We have noncontributory defined benefit retirement plans for substantially all full-time employees that provide pension benefits. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. We use a measurement date of December 31 for our pension and OPEB plans.

See Note 2 for information related to the implementation of SFAS No. 158 as of December 31, 2006.

COSTS OF BENEFIT PLANS

Prior service costs and benefits are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, we use a five-year averaging method for a portion of the pension assets and fair value for the remaining portion. We have historically used the five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

The components of the net periodic benefit cost for the years ended December 31 were:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$45**	$47	$54	**$9**	$9	$12
Interest cost	**117**	117	110	**33**	33	31
Expected return on plan assets	**(148)**	(147)	(155)	**(6)**	(5)	(5)
Amortization of actuarial loss[a]	**18**	21	6	**4**	6	4
Other amortization, net[a]	**–**	–	(1)	**5**	5	3
Net periodic cost	**$32**	$38	$14	**$45**	$48	$45

[a] Adjusted to reflect PEF's rate treatment (See Note 16B)

In addition to the net periodic cost reflected above, in 2005, we recorded costs for special termination benefits related to a voluntary enhanced retirement program of $123 million for pension benefits and $19 million for other postretirement benefits.

No amounts related to our OPEB plans were recognized as a component of other comprehensive income (OCI) for the years ended December 31, 2006, 2005 and 2004. Pre-tax amounts related to our pension plans recognized as a component of OCI for the years ended December 31, 2006, 2005 and 2004 were net actuarial gains (losses) of $78 million, $(41) million and $(202) million, respectively.

The following weighted-average actuarial assumptions were used in the calculation of its net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.65%**	5.70%	6.30%	**5.65%**	5.70%	6.30%
Rate of increase in future compensation						
Bargaining	**3.50%**	3.50%	3.50%	**–**	–	–
Supplementary plans	**5.25%**	5.25%	5.00%	**–**	–	–
Expected long-term rate of return on plan assets	**9.00%**	9.00%	9.25%	**8.30%**	8.25%	8.50%

The expected long-term rates of return on plan assets were determined by considering long-term historical returns for the plans and long-term projected returns based on the plans' target asset allocation. For all pension plan assets and a substantial portion of OPEB plans assets, those benchmarks support an expected long-term rate of return between 9.0% and 9.5%. We have chosen to use an expected long-term rate of 9.0%, the low end of the range, beginning in 2005.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

Reconciliations of the changes in our benefit obligations and our funded status as of December 31, 2006 and 2005 are presented below, followed by related supplementary information.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Projected benefit obligation at January 1	**$2,164**	$1,961	**$650**	$538
Service cost	**45**	47	**9**	9
Interest cost	**117**	117	**33**	33
Benefit payments	**(174)**	(182)	**(29)**	(33)
Plan amendment	**18**	–	**(4)**	–
Special termination benefits	**–**	123	**–**	19
Actuarial (gain) loss	**(47)**	98	**(31)**	84
Obligation at December 31	**2,123**	2,164	**628**	650
Fair value of plan assets at December 31	**1,836**	1,770	**74**	76
Funded status	**$(287)**	$(394)	**$(554)**	$(574)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.123 billion and $2.164 billion at December 31, 2006 and 2005, respectively. Those plans had accumulated benefit obligations totaling $2.083 billion and $2.117 billion at December 31, 2006 and 2005, respectively, and plan assets of $1.836 billion and $1.770 billion at December 31, 2006 and 2005, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Current liabilities	**$14**	$–	**$1**	$–
Noncurrent liabilities	**273**	347	**553**	390

The table below provides a summary of amounts not yet recognized as a component of net periodic cost, as of December 31.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Recognized in accumulated other comprehensive loss				
Net actuarial loss	**$49**	$260	**$7**	$–
Other, net	**5**	–	**1**	–
Recognized in regulatory assets, net				
Net actuarial loss (gain)	**215**	83	**108**	(19)
Other, net	**22**	–	**28**	24
Recognized as an intangible asset				
Prior service cost	**–**	23	**–**	–
Not recognized in the Consolidated Balance Sheets				
Net actuarial loss	**–**	47	**–**	170
Other, net	**–**	–	**–**	14
Total not yet recognized as a component of net periodic cost[a]	**$291**	$413	**$144**	$189

[a] All components are adjusted to reflect PEF's rate treatment (See Note 16B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2007.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss[a]	$15	$6
Amortization of other, net[a]	2	5

[a] Adjusted to reflect PEF's rate treatment (See Note 16B).

The following weighted-average actuarial assumptions were used in the calculation of our year-end obligations:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	**2006**	2005
Discount rate	**5.95%**	5.65%	**5.95%**	5.65%
Rate of increase in future compensation				
Bargaining	**4.25%**	3.50%	**–**	–
Supplementary plans	**5.25%**	5.25%	**–**	–
Initial medical cost trend rate for pre-Medicare Act benefits	**–**	–	**9.00%**	8.25%
Initial medical cost trend rate for post-Medicare Act benefits	**–**	–	**9.00%**	8.25%
Ultimate medical cost trend rate	**–**	–	**5.00%**	5.00%
Year ultimate medical cost trend rate is achieved	**–**	–	**2014**	2013

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan as defined in EITF Issue No. 03-4, "Determining the Classification and Benefit Attribution Method for a 'Cash Balance' Pension Plan." Therefore, effective December 31, 2003, we began to use the traditional unit credit method for purposes of measuring the benefit obligation of this plan. Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$2
Effect on postretirement benefit obligation	29
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(1)
Effect on postretirement benefit obligation	(22)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, substantially all employer contributions represent benefit payments made directly from our assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments. The OPEB benefits payments for 2006 are also reduced by prescription drug-related federal subsidies received, which totaled $2 million.

Reconciliations of the fair value of plan assets at December 31 follow:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$1,770**	$1,774	**$76**	$70
Actual return on plan assets	**222**	170	**8**	5
Benefit payments	**(174)**	(182)	**(29)**	(33)
Employer contributions	**18**	8	**19**	34
Fair value of plan assets at December 31	**$1,836**	$1,770	**$74**	$76

The asset allocation for the benefit plans at the end of 2006 and 2005 and the target allocation for the plans, by asset category, are presented in the following tables:

	Pension Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
Equity – domestic	40%	**44%**	44%
Equity – international	15%	**23%**	22%
Debt – domestic	20%	**12%**	13%
Debt – international	10%	**9%**	8%
Other	15%	**12%**	13%
Total	100%	**100%**	100%

	Other Postretirement Benefits		
	Target Allocations	Percentage of Plan Assets at Year End	
Asset Category	2007	**2006**	2005
Equity – domestic	27%	**30%**	32%
Equity – international	10%	**15%**	16%
Debt – domestic	46%	**40%**	37%
Debt – international	7%	**7%**	6%
Other	10%	**8%**	9%
Total	100%	**100%**	100%

For pension plan assets and a substantial portion of OPEB plan assets, we set target allocations among asset classes to provide broad diversification to protect against large investment losses and excessive volatility, while recognizing the importance of offsetting the impacts of benefit cost escalation. In addition, external investment managers who have complementary investment philosophies and approaches are employed to manage the assets. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2007, we expect to make $60 million of contributions directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $143, $147, $151, $154, $154 and $838, respectively. The expected benefit payments for the OPEB plan for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $41, $45, $48, $51, $53 and $284, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2007 through 2011 and in total for 2012 through 2016, in millions, are approximately $3, $4, $4, $5, $5 and $38, respectively.

B. Florida Progress Acquisition

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 16A is adjusted as appropriate to reflect PEF's rate treatment.

17. RISK MANAGEMENT ACTIVITIES AND DERIVATIVES TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk if the counterparty fails to perform under the contract. We minimize such risk by performing credit reviews using, among other things, publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

As discussed in Note 3, on December 13, 2006, our board of directors approved a plan to pursue the disposition of substantially all of PVI's remaining CCO physical and commercial assets and on July 12, 2006, our board of directors approved a plan to divest of Gas. The transaction to sell Gas closed on October 2, 2006. We expect to complete the disposition plan for CCO in 2007.

Due to the reclassification of the remaining CCO operations to discontinued operations in December 2006, management determined that it was no longer probable that the forecasted transactions underlying certain derivative contracts covering approximately 95 Bcf of natural gas would be fulfilled. Therefore, these contracts were no longer treated as cash flow hedges, and were dedesignated and cash flow hedge accounting was discontinued.

At December 31, 2006, derivative assets and derivative liabilities related to CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. At December 31, 2005, derivative assets and derivative liabilities related to Gas and CCO are included in assets of discontinued operations and liabilities of discontinued operations, respectively, on the Consolidated Balance Sheet. For the years ending December 31, 2006, 2005 and 2004, excluding amounts reclassified to earnings due to discontinuance of the related cash flow hedges, net gains and losses from derivative instruments related to Gas and CCO on a consolidated basis were not material and are included in discontinued operations, net of tax on the Consolidated Statements of Income. For the year ending December 31, 2006, discontinued operations, net of tax includes $74 million in after-tax deferred income, which was reclassified to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2005, there were no reclassifications to earnings due to discontinuance of the related cash flow hedges. For the year ending December 31, 2004, discontinued operations, net of tax includes $10 million in after-tax deferred losses, which were reclassified to earnings due to discontinuance of the related cash flow hedges.

A. Commodity Derivatives

GENERAL

Most of our commodity contracts are not derivatives pursuant to SFAS No. 133 or qualify as normal purchases or sales pursuant to SFAS No. 133. Therefore, such contracts are not recorded at fair value.

In 2003, we recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the provisions of FASB Derivatives Implementation Group Issue C20, "Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (DIG Issue C20). The related liability is being amortized to earnings over the term of the related contract (See Note 20). At December 31, 2006 and 2005, the remaining liability was $14 million and $19 million, respectively.

ECONOMIC DERIVATIVES

Derivative products, primarily electricity and natural gas contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures. Gains and losses from such contracts were not material to our or the Utilities' results of operations during the years ended December 31, 2006, 2005 and 2004. Excluding $107 million of derivative assets, which are included in assets of discontinued operations on the Consolidated Balance Sheet and $31 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2006, we did not have material outstanding positions in such contracts at December 31, 2006 and 2005, other than those receiving regulatory accounting treatment at PEF, as discussed below. Our discontinued operations did not have material outstanding positions in such contracts at December 31, 2005.

PEF has derivative instruments related to its exposure to price fluctuations on fuel oil and natural gas purchases. These instruments receive regulatory accounting treatment. Unrealized gains and losses are recorded in regulatory liabilities and regulatory assets on the Balance Sheets, respectively, until the contracts are settled. Once settled, any realized gains or losses are passed through the fuel clause. At December 31, 2006, the fair values of these instruments were a $2 million long-term derivative asset position included in other assets and deferred debits, an $87 million short-term derivative liability position included in other current liabilities and a $36 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet. At December 31, 2005, the fair values of the instruments were a $77 million short-term derivative asset position included in other current assets, a $45 million long-term derivative asset position included in other assets and deferred debits and a $49 million long-term derivative liability position included in other liabilities and deferred credits on the Balance Sheet.

On January 8, 2007, we entered into derivative contracts to hedge economically a portion of our 2007 synthetic fuels cash flow exposure to the risk of rising oil prices over an average annual oil price range of $63 to $77 per barrel on a New York Mercantile Exchange (NYMEX) basis. The notional quantity of these oil price hedge instruments is 25 million barrels and will provide protection for the equivalent of approximately 8 million tons of 2007 synthetic fuels production. The cost of the hedges was approximately $65 million. The contracts will be marked-to-market with changes in fair value recorded through earnings from synthetic fuels production.

CASH FLOW HEDGES

Our subsidiaries designate a portion of commodity derivative instruments as cash flow hedges under SFAS No. 133. The objective for holding these instruments is to hedge exposure to market risk associated with fluctuations in the price of natural gas and power for our forecasted purchases and sales. Realized gains and losses are recorded net in operating revenues or operating expenses, as appropriate. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2006, 2005 and 2004.

The fair values of commodity cash flow hedges at December 31 were as follows:

(in millions)	**2006**	2005
Fair value of assets	**$2**	$7
Fair value of liabilities	**–**	(4)
Fair value, net	**$2**	$3

Our discontinued operations did not have material outstanding positions in commodity cash flow hedges at December 31, 2006. Excluded from the table above are $163 million of derivative assets, which are included in assets of discontinued operations, and $54 million of derivative liabilities, which are included in liabilities of discontinued operations on the Consolidated Balance Sheet at December 31, 2005.

At December 31, 2006, the amount recorded in our AOCI related to commodity cash flow hedges was not material. At December 31, 2005, we had $69 million of after-tax deferred income recorded in AOCI related to commodity cash flow hedges.

B. Interest Rate Derivatives – Fair Value or Cash Flow Hedges

We use cash flow hedging strategies to reduce exposure to changes in cash flow due to fluctuating interest rates. We use fair value hedging strategies to reduce exposure to changes in fair value due to interest rate changes. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates

On November 7, 2006, Progress Energy commenced a tender offer for up to $550 million aggregate principal amount of its 2011 and 2012 senior notes. Subsequently, we executed a total notional amount of $550 million of reverse treasury locks to reduce exposure to changes in cash flow due to fluctuating interest rates, which were then terminated on December 1, 2006. On December 6, 2006, Progress Energy repurchased, pursuant to the tender offer, $550 million, or 53.0 percent, of the outstanding aggregate principal amount of its 7.10% Senior Notes due March 1, 2011, at 108.361 percent of par, or $596 million, plus accrued interest.

The fair values of open interest rate hedges at December 31 were as follows:

(in millions)	**2006**	2005
Interest rate cash flow hedges	**$(2)**	$1
Interest rate fair value hedges	**(1)**	(2)

CASH FLOW HEDGES

Gains and losses from cash flow hedges are recorded in AOCI and amounts reclassified to earnings are included in net interest charges as the hedged transactions occur. Amounts in AOCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The ineffective portion of interest rate cash flow hedges was not material to our results of operations for 2006, 2005 and 2004.

The following table presents selected information related to interest rate cash flow hedges included in AOCI at December 31, 2006:

(term in years; dollars in millions)	Maximum Term	Accumulated Other Comprehensive Loss, net of Tax[a]	Portion Expected to be Reclassified to Earnings during the Next 12 Months[b]
Interest rate cash flow hedges	1	$(14)	$(2)

[a] Includes amounts related to terminated hedges
[b] Actual amounts that will be reclassified to earnings may vary from the expected amounts presented above as a result of changes in interest rates

PEC entered into a $50 million forward starting swap on June 2, 2006, and PEF entered into a $50 million forward starting swap on June 6, 2006, to mitigate exposure to interest rate risk on their respective anticipated debt issuances in 2007. These swaps were designated as cash flow hedges as of July 1, 2006

At December 31, 2005, including amounts related to terminated hedges, we had $13 million of after-tax deferred losses recorded in AOCI related to interest rate cash flow hedges. At December 31, 2005, we had $100 million notional of interest rate cash flow hedges, which were settled in the first quarter of 2006.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2006 and 2005, we had $50 million notional and $150 million notional, respectively, of interest rate fair value hedges.

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, the Parent had issued $1.34 billion of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the Consolidated Balance Sheet.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of PUHCA 1935. The repeal of PUHCA 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction management and other centralized administrative, management and support services. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. Billings from affiliates are capitalized or expensed depending on the nature of the services rendered. Amounts receivable from and/or payable to affiliated companies for these services are included in receivables from affiliated companies and payables to affiliated companies on the Balance Sheets.

PESC provides the majority of the affiliated services under the approved agreements. Services provided by PESC during 2006, 2005 and 2004 to PEC amounted to $188 million, $202 million and $209 million, respectively, and services provided to PEF were $165 million, $169 million and $165 million, respectively.

Progress Fuels sold coal to PEF at cost in 2006 and for an insignificant profit in 2005 and 2004. These intercompany revenues and expenses are eliminated in consolidation; however, in accordance with SFAS No. 71, profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. Sales, net of insignificant profits, if any, of $321 million, $402 million and $331 million for the years ended December 31, 2006, 2005 and 2004, respectively, are included in fuel used in electric generation on the Consolidated Statements of Income. In 2006, PEF began entering into coal contracts on its own behalf.

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are: PEC, PEF, and Coal and Synthetic Fuels.

Our PEC and PEF business segments are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. These electric operations also distribute and sell electricity to other utilities, primarily in the eastern United States.

Our Coal and Synthetic Fuels segment is involved in the production and sale of coal-based solid synthetic fuels as defined under the Code, the operation of synthetic fuels facilities for third parties, and coal terminal services. On May 22, 2006, we idled our synthetic fuels facilities due to significant uncertainty surrounding synthetic fuels production. During September and October 2006, we resumed limited synthetic fuels production at our facilities, which continued through the end of 2006. See Notes 8 and 9 for additional information.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC as well as other nonregulated businesses. These nonregulated businesses do not separately meet the disclosure requirements of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Included in the 2004 losses is a $43 million pre-tax ($29 million after-tax) settlement agreement that our subsidiary Strategic Resource Solutions Corp. reached with the San Francisco United School District related to civil proceedings. The profit or loss of our reportable segments plus the profit or loss of Corporate and Other represents our total income from continuing operations.

As discussed in Note 3, prior to 2006, our former Progress Ventures segment was engaged in nonregulated electric generation and energy marketing activities and natural gas drilling and production. Also, prior to 2006, PT LLC was included within the Corporate and Other segment, and Dixie Fuels and other fuels business were included within the Coal and Synthetic Fuels segment. In connection with their respective divestitures, certain of which are expected to close in 2007, these operations were reclassified to discontinued operations in 2006 and therefore are not included in the results from continuing operations during the periods reported. For comparative purposes, prior year results have been restated to conform to the current segment presentation.

The postretirement and severance charges incurred in 2005 resulted from a workforce restructuring and voluntary enhanced retirement program that was approved in February 2005 and concluded in December 2005.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost except for transactions between PEF and the Coal and Synthetic Fuels segment, which are at rates set by the FPSC. In accordance with SFAS No. 71, profits on intercompany sales between PEF and the Coal and Synthetic Fuels segment are not eliminated if the sales price is reasonable and the future recovery of sales price through the ratemaking process is probable. The profits realized for 2006, 2005 and 2004 were not significant. Prior to 2006, income tax expense (benefit) by segment includes the Parent's allocation to profitable subsidiaries of income tax benefits not related to acquisition interest expense in accordance with the Tax Agreement. Due to the repeal of PUHCA 1935, the Parent stopped allocating these tax benefits in 2006.

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments. Operational results and assets of discontinued operations are not included in the table presented below.

(in millions)	PEC	PEF	Coal and Synthetic Fuels	Corporate and Other	Eliminations	Totals
As of and for the year ended December 31, 2006						
Revenues						
Unaffiliated	$4,086	$4,639	$845	$–	$–	$9,570
Intersegment	–	–	321	408	(729)	–
Total revenues	4,086	4,639	1,166	408	(729)	9,570
Depreciation and amortization	571	404	19	38	–	1,032
Interest income	25	15	2	85	(66)	61
Total interest charges, net	215	150	15	312	(67)	625
Impairment of long-lived assets and investments	–	–	91	–	–	91
Income tax expense (benefit)	265	193	(145)	(109)	–	204
Segment profit (loss)	454	326	(76)	(190)	–	514
Total assets	12,020	8,593	268	15,204	(11,271)	24,814
Capital and investment expenditures	808	741	3	12	(9)	1,555
As of and for the year ended December 31, 2005						
Revenues						
Unaffiliated	$3,991	$3,955	$1,222	$–	$–	$9,168
Intersegment	–	–	402	437	(839)	–
Total revenues	3,991	3,955	1,624	437	(839)	9,168
Depreciation and amortization	561	334	34	34	–	963
Interest income	8	1	3	94	(90)	16
Total interest charges, net	192	126	23	318	(85)	574
Postretirement and severance charges	55	102	5	1	–	163
Income tax expense (benefit)	239	121	(354)	(43)	–	(37)
Segment profit (loss)	490	258	163	(190)	–	721
Total assets	11,502	8,318	450	17,898	(13,672)	24,496
Capital and investment expenditures	682	543	5	19	(19)	1,230
As of and for the year ended December 31, 2004						
Revenues						
Unaffiliated	$3,629	$3,525	$886	$13	$–	$8,053
Intersegment	–	–	333	430	(763)	–
Total revenues	3,629	3,525	1,219	443	(763)	8,053
Depreciation and amortization	570	281	34	34	–	919
Interest income	4	–	6	90	(89)	11
Total interest charges, net	192	114	23	322	(85)	566
Postretirement and severance charges	2	–	1	–	–	3
Income tax expense (benefit)	239	174	(280)	(66)	–	67
Segment profit (loss)	459	333	90	(208)	–	673
Total assets	10,787	7,924	540	17,465	(13,550)	23,166
Capital and investment expenditures	620	492	6	20	(12)	1,126

20. OTHER INCOME AND OTHER EXPENSE

Other income and expense includes interest income, impairment of investments, and other income and expense items as discussed below. Nonregulated energy and delivery services include power protection services and mass market programs such as surge protection, appliance services and area light sales, and delivery, transmission and substation work for other utilities. AFUDC equity represents the estimated equity costs of capital funds necessary to finance the construction of new regulated assets. The components of other, net as shown on the ~~accompanying Consolidated Statements of Income for the~~ years ended December 31 were as follows:

(in millions)	**2006**	2005	2004
Other income			
Nonregulated energy and delivery services income	**$41**	$32	$28
DIG Issue C20 amortization (Note 17A)	**5**	7	9
Contingent value obligation unrealized gain (Note 15)	**–**	6	9
Gain on sale of Level 3 stock[a]	**32**	–	–
Investment gains	**4**	4	2
Income from equity investments	**1**	1	3
AFUDC equity	**21**	16	12
Reversal of indemnification liability (Note 21B)	**29**	–	–
Other	**16**	16	14
Total other income	**149**	82	77
Other expense			
Nonregulated energy and delivery services expenses	**27**	23	21
Donations	**20**	18	15
Contingent value obligation unrealized loss (Note 15)	**25**	–	–
Loss from equity investments	**8**	13	8
Loss on debt redemption[b]	**59**	–	–
FERC audit settlement	**–**	7	–
Indemnification liability (Note 21B)	**13**	16	–
Other	**15**	12	29
Total other expense	**167**	89	73
Other, net	**$(18)**	$(7)	$4

[a] Other income includes pre-tax gains of $32 million for the year ended December 31, 2006, from the sale of approximately 20 million shares of Level 3 stock received as part of the sale of our interest in PT LLC (See Note 3D). These gains are prior to the consideration of minority interest.

[b] On November 27, 2006, Progress Energy redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. On December 6, 2006, Progress Energy repurchased, pursuant to a tender offer, $550 million, or 55.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. We recognized a total pre-tax loss of $59 million in conjunction with these redemptions.

21. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be ~~precisely estimated.~~

A. Hazardous and Solid Waste

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the Environmental Protection Agency (EPA) to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina or the state of Florida, as described below in greater detail. Various materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each potentially responsible parties (PRPs) at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. We evaluate potential claims against other potential PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of these potential claims cannot be predicted. No material claims are currently pending. A discussion of sites by legal entity follows.

We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. We measure our liability for these sites based on available evidence including our experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. For all sites, as assessments are developed and analyzed, we will accrue costs for the sites to the extent our liability is probable and the costs can be reasonably estimated. Because the extent of environmental impact, allocation among PRPs for all sites, remediation alternatives (which could involve either minimal or significant efforts), and concurrence of the regulatory authorities have not yet reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates will change and additional losses, which could be material, may be incurred in the future.

The following table contains information about accruals for environmental remediation expenses described below. Accruals for probable and estimable costs related to various environmental sites, which were included in other liabilities and deferred credits on the Balance Sheets, at December 31 were:

(in millions)	**2006**	2005
PEC		
MGP and other sites[a]	**$22**	$7
PEF		
Remediation of distribution and substation transformers	**43**	20
MGP and other sites	**18**	18
Total PEF environmental remediation accruals[b]	**61**	38
Progress Energy nonregulated operations	**3**	3
Total Progress Energy environmental remediation accruals	**$86**	$48

[a] Expected to be paid out over one to five years
[b] Expected to be paid out over one to fifteen years

In addition to the Utilities' sites, discussed under "PEC" and "PEF" below, our environmental sites include the following related to our nonregulated operations.

In 2001, we, through our Progress Fuels subsidiary, established an accrual to address indemnities and retained an environmental liability associated with the sale of our Inland Marine Transportation business. At December 31, 2006 and 2005, the remaining accrual balance was approximately $3 million. Expenditures related to this liability were not material during 2006 and 2005.

On March 24, 2005, we completed the sale of our Progress Rail subsidiary. In connection with the sale, we incurred indemnity obligations related to certain pre-closing liabilities, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

There are currently eight former MGP sites and a number of other sites associated with PEC that have required or are anticipated to require investigation and/or remediation. Three of these sites are in the long-term monitoring phase.

For the year ended December 31, 2006, including the Ward Transformer site and MGP sites discussed below, PEC accrued approximately $21 million and spent approximately $6 million. For the year ended December 31, 2005, PEC accrued approximately $4 million and spent approximately $6 million. In October 2006, PEC received orders from the NCUC and SCPSC to defer and amortize certain environmental remediation expenses (See Note 7B).

In September 2005, the EPA advised PEC that it had been identified as a PRP at the Carolina Transformer site located in Fayetteville, N.C. The EPA offered PEC and a number of other PRPs the opportunity to share in the reimbursement to the EPA of past expenditures in addressing conditions at the site, which are currently approximately $32 million. In May 2006, a meeting was called by the EPA to discuss a settlement proposal among the PRPs. An agreement among PRPs has not been reached; consequently, it is not possible at this time to reasonably estimate the amount of PEC's share of the reimbursement for remediation of the Carolina Transformer site. The outcome of this matter cannot be predicted.

During the fourth quarter of 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. The EPA offered PEC and a number of other PRPs the opportunity to negotiate cleanup of the site and reimbursement to the EPA for EPA's past expenditures in addressing conditions at the site. In September 2005, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the site. For the year ended December 31, 2005, PEC accrued approximately $3 million for its portion of the EPA's estimated remediation costs and the EPA's past costs. For the year ended December 31, 2006, based upon continuing assessment work performed at the site, PEC recorded an additional $9 million accrual for its portion of the estimated remediation costs. At December 31, 2006, after cumulative expenditures for the Ward site of approximately $3 million, PEC's recorded liability for the site was approximately $9 million. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. The outcome of this matter cannot be predicted.

For the year ended December 31, 2006, based upon newly available data for several of PEC's MGP sites, which had individual site remediation costs ranging from approximately $2 million to $4 million, a remediation liability of approximately $12 million was recorded for the minimum estimated total remediation cost for all of PEC's remaining MGP sites. However, the maximum amount of the range for all the sites cannot be determined at this time as one of the remaining sites is significantly larger than the sites for which we have historical experience.

PEF

PEF has received approval from the FPSC for recovery of the majority of costs associated with the remediation of distribution and substation transformers through the Environmental Cost Recovery Clause (ECRC). Under agreements with the Florida Department of Environmental Protection, PEF is in the process of examining distribution transformer sites and substation sites for mineral oil-impacted soil remediation caused by equipment integrity issues. PEF has reviewed a number of distribution transformer sites and all substation sites. Based on changes to the estimated time frame for inspections of distribution transformer sites, PEF currently expects to have completed this review by the end of 2008. Should further sites be identified, PEF believes that any estimated costs would also be recovered through the ECRC. For the years ended December 31, 2006 and 2005, PEF accrued approximately $42 million and $2 million, respectively, due to additional sites expected to require remediation and spent approximately $19 million and $9 million, respectively, related to the remediation of transformers. At December 31, 2006, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

The amounts for MGP and other sites, in the table above, relate to two former MGP sites and other sites associated with PEF that have required or are anticipated to require investigation and/or remediation. The amounts include approximately $12 million in insurance claim settlement proceeds received in 2004, which are restricted for use in addressing costs associated with environmental liabilities. For the year ended December 31, 2006, PEF made no accruals and PEF's expenditures and insurance proceeds were not material to our results of operations or financial condition. For the year ended December 31, 2005, PEF made no material accruals, spent approximately $1 million and received approximately $1 million of additional insurance proceeds.

B. Air and Water Quality

We are subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations include the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR), the NOx SIP Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and the Clean Smokestacks Act. At December 31, 2006, cumulative capital expenditures to date to comply with these environmental laws and regulations were $937 million, including $909 million and $28 million at PEC and PEF, respectively.

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and SO_2 from their North Carolina coal-fired power plants in phases by 2013. The Clean Smokestacks Act requires PEC to amortize $569 million, representing 70 percent of the original cost estimate of $813 million, during the five-year period ending December 31, 2007. The Clean Smokestacks Act permits PEC the flexibility to vary the amortization schedule for recording of the compliance costs from none up to $174 million per year. For the years ended December 31, 2006, 2005 and 2004, PEC recognized amortization of $140 million, $147 million and $174 million, respectively, and has recognized $535 million in cumulative amortization through December 31, 2006. The remaining amortization requirement of $34 million will be recorded during the one-year period ending December 31, 2007. The NCUC will hold a hearing prior to December 31, 2007, to determine cost-recovery amounts for 2008 and 2009.

Two of PEC's largest coal-fired generation plants (the Roxboro No. 4 and Mayo Units) impacted by the Clean Smokestacks Act are jointly owned. Pursuant to joint ownership agreements, the joint owners are required to pay a portion of the costs of owning and operating these plants. PEC has determined that the most cost-effective Clean Smokestacks Act compliance strategy is to maximize the SO_2 removal from its larger coal-fired units, including Roxboro No. 4 and Mayo, so as to avoid the installation of expensive emission controls on its smaller coal-fired units. In order to address the joint owner's concerns that such a compliance strategy would result in a disproportionate share of the cost of compliance on the jointly owned units, PEC entered into an agreement with the joint owner to limit its aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act to approximately $38 million. PEC recorded a related liability for the joint owner's share of estimated costs in excess of the contract amount. At December 31, 2006, the amount of the liability was $29 million and had increased from $16 million at December 31, 2005, based upon the respective current estimates for Clean Smokestacks Act compliance. Because PEC has taken a systemwide compliance approach, its North Carolina retail customers have significantly benefited from the strategy of focusing emission reduction efforts on the jointly owned units, and, therefore, PEC believes that any costs in excess of the joint owner's share should be recovered from North Carolina retail customers, consistent with other capital expenditures associated with PEC's compliance with the Clean Smokestacks Act. On November 2, 2006, PEC notified the NCUC of its intent to record these estimated excess costs as part of the $569 million amortization required to be recorded by December 31, 2007, and subsequently reclassified $29 million of indemnification expense to Clean Smokestacks Act amortization (See Note 20).

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

At December 31, 2006, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2007	2008	2009	2010	2011	Thereafter
Fuel	$2,128	$1,514	$1,057	$509	$390	$1,251
Purchased power	485	454	422	377	381	4,165
Construction obligations	393	197	8	3	–	–
Other purchase obligations	86	71	23	22	15	74
Total	$3,092	$2,236	$1,510	$911	$786	$5,490

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel. Our payments under these commitments were $3.168 billion, $3.071 billion and $2.033 billion for 2006, 2005 and 2004, respectively.

Both PEC and PEF have ongoing purchased power contracts with certain cogenerators (primarily QFs) with expiration dates ranging from 2007 to 2033. These purchased power contracts generally provide for capacity and energy payments.

Pursuant to the terms of the 1981 Power Coordination Agreement, as amended, between PEC and Power Agency, PEC is obligated to purchase a percentage of Power Agency's ownership capacity of, and energy from, Harris. In 1993, PEC and Power Agency entered into an agreement to restructure portions of their contracts covering power supplies and interests in jointly owned units. Under the terms of the 1993 agreement, PEC increased the amount of capacity and energy purchased from Power Agency's ownership interest in Harris, and the buyback period was extended six years through 2007. The estimated minimum annual payments for these purchases, which reflect capacity and energy costs, total approximately $34 million. These contractual purchases totaled $38 million, $37 million and $39 million for 2006, 2005 and 2004, respectively.

PEC has a long-term agreement for the purchase of power and related transmission services from Indiana Michigan Power Company's Rockport Unit No. 2 (Rockport). The agreement provides for the purchase of 250 MW of capacity through 2009 with estimated minimum annual payments of approximately $42 million, representing capital-related capacity costs. Total purchases (including energy and transmission use charges) under the Rockport agreement amounted to $80 million, $71 million and $62 million for 2006, 2005 and 2004, respectively.

PEC executed two long-term agreements for the purchase of power from Broad River LLC's Broad River facility (Broad River). One agreement provides for the purchase of approximately 500 MW of capacity through 2021 with an original minimum annual payment of approximately $16 million, primarily representing capital-related capacity costs. The second agreement provided for the additional purchase of approximately 335 MW of capacity through 2022 with an original minimum annual payment of approximately $16 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River agreements amounted to $40 million, $44 million and $42 million in 2006, 2005 and 2004, respectively.

PEC has various pay-for-performance contracts with QFs for approximately 327 MW of capacity expiring at various times through 2014. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $182 million, $112 million and $90 million in 2006, 2005 and 2004, respectively.

PEF has long-term contracts for approximately 489 MW of purchased power with other utilities, including a contract with The Southern Company for approximately 414 MW of purchased power annually through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $162 million, $175 million and $128 million for 2006, 2005 and 2004, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $65 million annually through 2009, $54 million for 2010 and $38 million annually thereafter through 2016.

PEF has ongoing purchased power contracts with certain QFs for 943 MW of capacity with expiration dates ranging from 2007 to 2033. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the generating capacity of each of the facilities. All commitments have been approved by the FPSC. Total capacity purchases under these contracts amounted to $277 million, $262 million and $247 million for 2006, 2005 and 2004, respectively. At December 31, 2006, minimum expected future capacity payments under these contracts were $289 million, $300 million, $271 million, $274 million and $288 million for 2007 through 2011, respectively, and $3.508 billion thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

On December 2, 2004, PEF entered into precedent and related agreements with Southern Natural Gas Company (SNG), Florida Gas Transmission Company (FGT), and BG LNG Services, LLC for the supply of natural gas and associated firm pipeline transportation to augment PEF's gas supply needs for the period from May 1, 2007, to April 30, 2027. The total cost to PEF associated with the agreements is approximately $3.9 billion. The transactions are subject to several conditions precedent, some of which have been satisfied, which include obtaining the FPSC's approval of the agreements, the completion and commencement of operation of the necessary related expansions to SNG's and FGT's respective natural gas pipeline systems, and other standard closing conditions. Due to the conditions in the agreements, the estimated costs associated with these agreements are not included in the contractual cash obligations table above.

In January 2006, PEF entered into a conditional contract with Gulfstream Natural Gas System, L.L.C. (Gulfstream) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from September 1, 2008, through January 1, 2031. The total cost to PEF associated with this agreement is approximately $777 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of the necessary related expansions to Gulfstream's natural gas pipeline system, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Cross Timbers Energy Services, Inc. for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013. The total cost to PEF associated with this agreement is approximately $877 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with Southeast Supply Header, L.L.C. (SESH) for firm pipeline transportation capacity to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2023. The total cost to PEF associated with this agreement is approximately $271 million. The transaction is subject to several conditions precedent, including Florida Public Service Commission approval, the completion and commencement of operation of the SESH pipeline project, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

In December 2006, PEF entered into a conditional contract with a private oil and gas company for the supply of natural gas to augment PEF's gas supply needs for the period from June 1, 2008, through May 31, 2013.

The total cost to PEF associated with this agreement is approximately $128 million. The transaction is subject to several conditions precedent, including the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions, and other standard closing conditions. Due to the conditions of this agreement the estimated costs associated with this agreement are not included in the contractual cash obligations table above.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $365 million, $91 million and $108 million for 2006, 2005 and 2004, respectively. At December 31, 2006, we had construction obligations related to Clean Smokestacks Act capital projects of $99 million and $9 million for 2007 and 2008, respectively, and none thereafter. We have purchase obligations related to various plant capital projects related to new generation and Florida CAIR of $294 million, $188 million, $8 million and $3 million for 2007 through 2010, respectively.

OTHER PURCHASE OBLIGATIONS

We have entered into various other contractual obligations primarily related to service contracts for operational services entered into by PESC, parts and services contracts, and a PEF service agreement related to the Hines Energy Complex. Our payments under these agreements were $91 million, $82 million and $44 million for 2006, 2005 and 2004, respectively.

We have entered into various other contractual obligations primarily related to capacity and service contracts for operational services associated with discontinued CCO operations. Total payments under these contracts were $18 million, $17 million and $15 million for 2006, 2005 and 2004, respectively. Estimated future payments under these contracts of $198 million are not reflected in the table presented at the beginning of this footnote. Included in these contracts are purchase obligations with two counterparties for pipeline capacity through 2018 and 2028. Payments under these agreements were $16 million, $15 million and $13 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are approximately $13 million for 2007, $12 million for 2008 through 2011 and approximately $76 million payable thereafter. We anticipate transferring the obligations under these contracts to a third party as part of our disposition strategy.

PEC has various purchase obligations for emission obligations, limestone supply and the purchase of capital parts. Total purchases under these contracts were $2 million, $10 million and $2 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are $21 million each for 2007 and 2008, $3 million each for 2009 through 2011 and $12 million thereafter.

PEC has various purchase obligations related to reactor vessel head replacements, power uprates and spent fuel storage. Total purchases under these contracts were $8 million for 2006, $13 million for 2005 and $17 million for 2004. We do not have any future purchase obligations under these contracts.

PEF has long-term service agreements for the Hines Energy Complex. Total payments under these contracts were $12 million, $8 million and $11 million for 2006, 2005 and 2004, respectively. Future obligations under these contracts are $11 million, $16 million, $14 million, $19 million and $12 million for 2007 through 2011, respectively, with approximately $62 million payable thereafter.

PEF has various purchase obligations and contractual commitments related to the purchase and replacement of machinery. Total payments under these contracts were $21 million for 2006 and $34 million for 2005. There were no payments under these contracts during 2004. Future obligations under these contracts are $22 million, $8 million and $6 million for 2007 through 2009, respectively.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $42 million for 2006 and $38 million each for 2005 and 2004. Our purchased power expense under agreements classified as operating leases was approximately $60 million, $14 million and $25 million in 2006, 2005 and 2004, respectively.

Assets recorded under capital leases at December 31 consisted of:

(in millions)	2006	2005
Buildings	$84	$30
Less: Accumulated amortization	(12)	(12)
Total	$72	$18

At December 31, 2006, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

(in millions)	Capital	Operating
2007	$6	$79
2008	8	63
2009	7	55
2010	8	40
2011	7	19
Thereafter	91	172
Minimum annual payments	127	$428
Less amount representing imputed interest	(55)	
Present value of net minimum lease payments under capital leases	$72	

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded in the Consolidated Statements of Income.

In 2005, PEF entered into an agreement for a new capital lease for a building completed during 2006. The lease term expires March 2047 and provides for annual payments of approximately $5 million from 2007 through 2026 for a total of approximately $103 million. The lease term provides for no payments during the last 20 years of the lease, during which period approximately $51 million of rental expense will be recorded.

In 2006, PEF extended the terms of an agreement for purchased power, which is classified as a capital lease, for an additional 10 years. Due to the conditions of the agreement, the capital lease will not be recorded on PEF's Balance Sheet until 2007. Therefore this capital lease is not included in the table above. The agreement calls for annual payments of approximately $27 million from 2007 through 2024 for a total of approximately $460 million.

Excluding the Utilities, we are also a lessor of land, buildings and other types of properties we own under operating leases with various terms and expiration dates. The leased buildings are depreciated under the same terms as other buildings included in diversified business property. Minimum rentals receivable under noncancelable leases are approximately $9 million, $7 million, $6 million, $4 million and $2 million for 2007 through 2011, respectively. Rents received under these operating leases totaled $9 million, $8 million and $6 million for 2006, 2005 and 2004, respectively.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals under noncancelable leases are $10 million for 2007 and none thereafter. PEC's rents received are contingent upon usage and totaled $31 million each for 2006 and 2005 and $32 million for 2004. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $72 million for 2006 and $63 million each for 2005 and 2004. PEF's minimum rentals under noncancelable leases are not material for 2007 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties, which are outside the scope of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes (See Note 18). Our guarantees include performance obligations under power supply agreements, tolling agreements, transmission agreements, gas agreements, fuel procurement agreements and trading operations. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2006, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2006, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations. Related to the sales of businesses, the latest notice period extends until 2012 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. In 2005, PEC entered into an agreement with the joint owner of certain facilities at the Mayo and Roxboro plants to limit their aggregate costs associated with capital expenditures to comply with the Clean Smokestacks Act and recognized a liability related to this indemnification (See Note 21B). PEC's maximum exposure cannot be determined. At December 31, 2006, the maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $208 million. At December 31, 2006 and 2005, we have recorded liabilities related to guarantees and indemnifications to third parties of approximately $60 million and $41 million, respectively. As current estimates change, it is possible that additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. Other Commitments and Contingencies

SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, the Utilities entered into contracts with the DOE under which the DOE agreed to begin taking spent nuclear fuel by no later than January 31, 1998. All similarly situated utilities were required to sign the same standard contract.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the United States Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. Our damages due to the DOE's breach will be significant, but have yet to be determined. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims.

The DOE and the Utilities agreed to, and the trial court entered, a stay of proceedings, in order to allow for possible efficiencies due to the resolution of legal and factual issues in previously filed cases in which similar claims are being pursued by other plaintiffs. These issues may include, among others, so-called "rate issues," or the minimum mandatory schedule for the acceptance of spent nuclear fuel and high-level radioactive waste by which the government was contractually obligated to accept contract holders' spent nuclear fuel and/or high-level waste, and issues regarding recovery of damages under a partial breach of contract theory that will be alleged to occur in the future. These issues have been or are expected to be presented in the trials or appeals that are currently scheduled to occur during 2006 and 2007. Resolution of these issues in other cases could facilitate agreements by the parties in the Utilities' lawsuit, or at a minimum, inform the court of decisions reached by other courts if they remain contested and require resolution in this case. In July 2005, the parties jointly requested a continuance of the stay through December 15, 2005, which the trial court granted. Subsequently, the trial court continued the stay until March 17, 2006. The trial court lifted the stay on March 22, 2006, and discovery has commenced. The trial court's scheduling order, issued on March 23, 2006, included an anticipated trial date in late 2007.

In July 2002, Congress passed an override resolution to Nevada's veto of the DOE's proposal to locate a permanent underground nuclear waste storage facility at Yucca Mountain, Nev. In January 2003, the state of Nevada; Clark County, Nev.; and the city of Las Vegas petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of the Congressional override resolution. These same parties also challenged the EPA's radiation standards for Yucca Mountain. On July 9, 2004, the Court rejected the challenge to the constitutionality of the resolution approving Yucca Mountain, but ruled that the EPA was wrong to set a 10,000-year compliance period in the radiation protection standard. In August 2005, the EPA issued new proposed standards. The proposed standards include a 1,000,000-year compliance period in the radiation protection standard. Comments were due November 21, 2005, and are being reviewed by the EPA. The EPA is expected to issue a new safety standard for the repository in early 2007. The DOE originally planned to submit a license application to the NRC to construct the Yucca Mountain facility by the end of 2004. However, in November 2004, the DOE announced it would not submit the license application until mid-2005 or later. The DOE did not submit the license application in 2005 and has since reported that the license application will be submitted by June 2008. Congress approved $450 million for fiscal year 2006 for the Yucca Mountain project, approximately $201 million less than requested by the DOE. The DOE requested $545 million for fiscal year 2007. The request has not been approved at this time and the DOE is operating under a continuing resolution that limits spending to the level of fiscal year 2006. The DOE has stated that if legislative changes requested by the Bush administration are enacted, the repository may be able to accept spent nuclear fuel starting in 2017, but 2020 is more probable due to anticipated litigation by the state of Nevada. The Utilities cannot predict the outcome of this matter.

With certain modifications and additional approvals by the NRC, including the installation of onsite dry cask storage facilities at Robinson, Brunswick and CR3, the Utilities' spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated on their respective systems through the expiration of the operating licenses, including any license extensions, of their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its operating license, including any license extensions.

SYNTHETIC FUELS MATTERS

A number of our subsidiaries and affiliates are parties to two lawsuits arising out of an Asset Purchase Agreement dated as of October 19, 1999, by and among U.S. Global, LLC (Global); the Earthco synthetic fuels facilities (Earthco); certain affiliates of Earthco; EFC Synfuel LLC (which is owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to Purchase Agreement as of August 23, 2000 (the Asset Purchase Agreement). Global has asserted that (1) pursuant to the Asset Purchase Agreement, it is entitled to an interest in two synthetic fuels facilities currently owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities and (2) it is entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities.

The first suit, *U.S. Global, LLC v. Progress Energy, Inc. et al.*, asserts the above claims in a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), and requests an unspecified amount of compensatory damages, as well as declaratory relief. The Progress Affiliates have answered the Complaint by generally denying all of Global's substantive allegations and asserting numerous substantial affirmative defenses. The case is at issue, but neither party has requested a trial. The parties are currently engaged in discovery in the Florida Global Case.

The second suit, *Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC*, was filed by the Progress Affiliates in the Superior Court for Wake County, N.C., seeking declaratory relief consistent with our interpretation of the Asset Purchase Agreement (the North Carolina Global Case). Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Since that time, the parties have been engaged in discovery in the Florida Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the suit related to amounts due to Global that were placed in escrow during the course of the Internal Revenue Service (IRS) audit of the Earthco synthetic fuels facilities. The audit was successfully resolved in 2006 and the escrow, which totaled $42 million at December 31, 2006, was paid to Global in January 2007. The remainder of the suit continues. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures in accordance with SFAS No. 5 to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the condensed consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039

(Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (the Notes Guarantee). In addition, Florida Progress guaranteed the payment of all distributions related to the $300 million Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The Preferred Securities Guarantee, considered together with the Notes Guarantee, constitutes a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and Preferred Securities Guarantee are listed on the New York Stock Exchange.

The Subordinated Notes may be redeemed at the option of Funding Corp. at par value plus accrued interest through the redemption date. The proceeds of any redemption of the Subordinated Notes will be used by the Trust to redeem proportional amounts of the Preferred Securities and common securities in accordance with their terms. Upon liquidation or dissolution of Funding Corp., holders of the Preferred Securities would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The yearly interest expense is $21 million and is reflected in the Consolidated Statements of Income.

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. As of December 31, 2006, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a special-purpose entity and in accordance with the provisions of FIN 46R, we deconsolidated the Trust on December 31, 2003. The deconsolidation was not material to our financial statements. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In the following tables, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the financial results of Florida Progress. The Other column includes the consolidated financial results of all other nonguarantor subsidiaries and elimination entries for all intercompany transactions. All applicable corporate expenses have been allocated appropriately among the guarantor and nonguarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other nonguarantor subsidiaries operated as independent entities. The accompanying condensed consolidating financial statements have been restated for all periods presented to reflect the operations of CCO, Gas, PT LLC, DeSoto, Rowan, Dixie Fuels and other fuels businesses as discontinued operations as described in Note 3.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2006 (in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$–	$4,637	$4,085	$8,722
Diversified business	–	839	9	848
Total operating revenues	–	5,476	4,094	9,570
Operating expenses				
Utility				
Fuel used in electric generation	–	1,835	1,173	3,008
~~Purchased power~~	~~–~~	~~766~~	~~334~~	~~1,100~~
Operation and maintenance	14	684	885	1,583
Depreciation and amortization	–	404	605	1,009
Taxes other than on income	–	309	191	500
Other	–	(2)	(1)	(3)
Diversified business				
Cost of sales	–	854	44	898
Depreciation and amortization	–	13	10	23
Impairment of assets	–	44	47	91
Other	–	36	16	52
Total operating expenses	14	4,943	3,304	8,261
Operating (loss) income	(14)	533	790	1,309
Other (expense) income, net	(33)	55	21	43
Interest charges, net	276	184	165	625
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(323)	404	646	727
Income tax (benefit) expense	(123)	90	237	204
Equity in earnings of consolidated subsidiaries	779	–	(779)	–
Minority interest in subsidiaries' income, net of tax	–	(9)	–	(9)
Income (loss) from continuing operations	579	305	(370)	514
Discontinued operations, net of tax	(8)	392	(327)	57
Net income (loss)	$571	$697	$(697)	$571

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2005 *(in millions)*	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$ –	$3,955	$3,990	$7,945
Diversified business	–	1,244	(21)	1,223
Total operating revenues	–	5,199	3,969	9,168
Operating expenses				
Utility				
Fuel used in electric generation	–	1,323	1,036	2,359
Purchased power	–	694	354	1,048
Operation and maintenance	12	852	906	1,770
Depreciation and amortization	–	334	588	922
Taxes other than on income	4	279	177	460
Other	–	(26)	(11)	(37)
Diversified business				
Cost of sales	–	1,267	86	1,353
Depreciation and amortization	–	21	20	41
Other	–	19	13	32
Total operating expenses	16	4,763	3,169	7,948
Operating (loss) income	(16)	436	800	1,220
Other income (expense), net	66	(5)	(52)	9
Interest charges, net	300	166	108	574
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(250)	265	640	655
Income tax (benefit) expense	(63)	(70)	96	(37)
Equity in earnings of consolidated subsidiaries	884	–	(884)	–
Minority interest in subsidiaries' loss, net of tax	–	29	–	29
Income (loss) from continuing operations	697	364	(340)	721
Discontinued operations, net of tax	–	10	(35)	(25)
Cumulative effect of change in accounting principle, net of tax	–	–	1	1
Net income (loss)	$697	$374	$(374)	$697

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Operating revenues				
Electric	$–	$3,525	$3,628	$7,153
Diversified business	–	895	5	900
Total operating revenues	–	4,420	3,633	8,053
Operating expenses				
Utility				
Fuel used in electric generation	–	1,175	836	2,011
Purchased power	–	567	301	868
Operation and maintenance	10	630	835	1,475
Depreciation and amortization	–	281	597	878
Taxes other than on income	(2)	254	173	425
Other	–	(2)	(11)	(13)
Diversified business				
Cost of sales	–	911	81	992
Depreciation and amortization	–	21	20	41
Other	–	46	58	104
Total operating expenses	8	3,883	2,890	6,781
Operating (loss) income	(8)	537	743	1,272
Other income (expense), net	65	(4)	(46)	15
Interest charges, net	295	152	119	566
(Loss) income from continuing operations before income tax, equity in earnings of consolidated subsidiaries and minority interest	(238)	381	578	721
Income tax (benefit) expense	(57)	12	112	67
Equity in earnings of consolidated subsidiaries	940	–	(940)	–
Minority interest in subsidiaries' loss, net of tax	–	19	–	19
Income (loss) from continuing operations	759	388	(474)	673
Discontinued operations, net of tax	–	86	–	86
Net income (loss)	$759	$474	$(474)	$759

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$6,337	$8,908	$15,245
Current assets				
Cash and cash equivalents	153	40	72	265
Short-term investments	21	–	50	71
Notes receivable from affiliated companies	58	37	(95)	–
Deferred fuel cost	–	–	196	196
Assets of discontinued operations	–	45	842	887
Other current assets	27	1,109	1,030	2,166
Total current assets	259	1,231	2,095	3,585
Deferred debits and other assets				
Investment in consolidated subsidiaries	10,740	–	(10,740)	–
Goodwill	–	1	3,654	3,655
Other assets and deferred debits	126	1,583	1,507	3,216
Total deferred debits and other assets	10,866	1,584	(5,579)	6,871
Total assets	$11,125	$9,152	$5,424	$25,701
Capitalization				
Common stock equity	$8,286	$2,708	$(2,708)	$8,286
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	6	4	10
Long-term debt, affiliate	–	309	(38)	271
Long-term debt, net	2,582	2,512	3,470	8,564
Total capitalization	10,868	5,569	787	17,224
Current liabilities				
Current portion of long-term debt	–	124	200	324
Notes payable to affiliated companies	–	77	(77)	–
Liabilities of discontinued operations	–	13	176	189
Other current liabilities	210	1,281	814	2,305
Total current liabilities	210	1,495	1,113	2,818
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	61	245	306
Regulatory liabilities	–	1,091	1,452	2,543
Accrued pension and other benefits	14	377	566	957
Other liabilities and deferred credits	33	559	1,261	1,853
Total deferred credits and other liabilities	47	2,088	3,524	5,659
Total capitalization and liabilities	$11,125	$9,152	$5,424	$25,701

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2005

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Utility plant, net	$–	$5,821	$8,621	$14,442
Current assets				
Cash and cash equivalents	239	239	127	605
Short-term investments	–	–	191	191
Notes receivable from affiliated companies	467	–	(467)	–
Deferred fuel cost	–	341	261	602
Assets of discontinued operations	–	757	1,809	2,566
Other current assets	22	992	1,029	2,043
Total current assets	728	2,329	2,950	6,007
Deferred debits and other assets				
Investment in consolidated subsidiaries	11,594	–	(11,594)	–
Goodwill	–	2	3,653	3,655
Other assets and deferred debits	259	1,561	1,138	2,958
Total deferred debits and other assets	11,853	1,563	(6,803)	6,613
Total assets	$12,581	$9,713	$4,768	$27,062
Capitalization				
Common stock equity	$8,038	$3,039	$(3,039)	$8,038
Preferred stock of subsidiaries – not subject to mandatory redemption	–	34	59	93
Minority interest	–	31	5	36
Long-term debt, affiliate	–	440	(170)	270
Long-term debt, net	3,873	2,636	3,667	10,176
Total capitalization	11,911	6,180	522	18,613
Current liabilities				
Current portion of long-term debt	404	109	–	513
Notes payable to affiliated companies	–	315	(315)	–
Short-term debt	–	102	73	175
Liabilities of discontinued operations	–	226	316	542
Other current liabilities	245	762	812	1,819
Total current liabilities	649	1,514	886	3,049
Deferred credits and other liabilities				
Noncurrent income tax liabilities	–	–	198	198
Regulatory liabilities	–	1,189	1,338	2,527
Accrued pension and other benefits	12	307	546	865
Other liabilities and deferred credits	9	523	1,278	1,810
Total deferred credits and other liabilities	21	2,019	3,360	5,400
Total capitalization and liabilities	$12,581	$9,713	$4,768	$27,062

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2006

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$1,295	$1,015	$(398)	$1,912
Investing activities				
Gross utility property additions	–	(718)	(705)	(1,423)
Diversified business property additions	–	(2)	–	(2)
Nuclear fuel additions	–	(12)	(102)	(114)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	1,239	415	1,654
Purchases of available-for-sale securities and other investments	(919)	(625)	(908)	(2,452)
Proceeds from sales of available-for-sale securities and other investments	898	724	1,009	2,631
Changes in advances to affiliates	409	(39)	(370)	–
Proceeds from repayment of long-term affiliate debt	131	–	(131)	–
Return of investment in consolidated subsidiaries	287	–	(287)	–
Other investing activities	(63)	(6)	46	(23)
Net cash provided (used) by investing activities	743	561	(1,033)	271
Financing activities				
Issuance of common stock	185	–	–	185
Proceeds from issuance of long-term debt, net	397	–	–	397
Net decrease in short-term debt	–	(102)	(73)	(175)
Retirement of long-term debt	(2,091)	(109)	–	(2,200)
Retirement of long-term affiliate debt	–	(131)	131	–
Dividends paid on common stock	(607)	–	–	(607)
Dividends paid to parent	–	(1,135)	1,135	–
Changes in advances from affiliates	–	(243)	243	–
Cash distributions to minority interests of consolidated subsidiary	–	(79)	–	(79)
Other financing activities	(8)	71	(52)	11
Net cash (used) provided by financing activities	(2,124)	(1,728)	1,384	(2,468)
Cash provided (used) by discontinued operations				
Operating activities	–	92	(6)	86
Investing activities	–	(139)	(2)	(141)
Financing activities	–	–	–	–
Net decrease in cash and cash equivalents	(86)	(199)	(55)	(340)
Cash and cash equivalents at beginning of year	239	239	127	605
Cash and cash equivalents at end of year	$153	$40	$72	$265

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2005 (in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$257	$409	$509	$1,175
Investing activities				
Gross utility property additions	–	(496)	(584)	(1,080)
Diversified business property additions	–	(6)	–	(6)
Nuclear fuel additions	–	(47)	(79)	(126)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	462	13	475
Purchases of available-for-sale securities and other investments	(1,702)	(405)	(1,878)	(3,985)
Proceeds from sales of available-for-sale securities and other investments	1,702	405	1,738	3,845
Changes in advances to affiliates	333	5	(338)	–
Proceeds from repayment of long-term affiliate debt	369	–	(369)	–
Other investing activities	(12)	(26)	1	(37)
Net cash provided (used) by investing activities	690	(108)	(1,496)	(914)
Financing activities				
Issuance of common stock	208	–	–	208
Proceeds from issuance of long-term debt, net	–	744	898	1,642
Net increase in short-term debt	(170)	(191)	(148)	(509)
Retirement of long-term debt	(160)	(104)	(300)	(564)
Retirement of long-term affiliate debt	–	(369)	369	–
Dividends paid on common stock	(582)	–	–	(582)
Dividends paid to parent	–	(2)	2	–
Changes in advances from affiliates	–	(101)	101	–
Other financing activities	(9)	53	(10)	34
Net cash (used) provided by financing activities	(713)	30	912	229
Cash provided (used) by discontinued operations				
Operating activities	–	93	201	294
Investing activities	–	(206)	(26)	(232)
Financing activities	–	(2)	–	(2)
Net increase in cash and cash equivalents	234	216	100	550
Cash and cash equivalents at beginning of year	5	23	27	55
Cash and cash equivalents at end of year	$239	$239	$127	$605

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2004

(in millions)	Parent	Subsidiary Guarantor	Other	Progress Energy, Inc.
Net cash provided by operating activities	$653	$469	$287	$1,409
Investing activities				
Gross utility property additions	–	(482)	(516)	(998)
Diversified business property additions	–	(6)	–	(6)
Nuclear fuel additions	–	–	(101)	(101)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	343	29	372
Purchases of available-for-sale securities and other investments	–	(569)	(2,565)	(3,134)
Proceeds from sales of available-for-sale securities and other investments	–	569	2,679	3,248
Changes in advances to affiliates	27	(5)	(22)	–
Contributions to consolidated subsidiaries	(15)	–	15	–
Other investing activities	–	(23)	(7)	(30)
Net cash provided (used) by investing activities	12	(173)	(488)	(649)
Financing activities				
Issuance of common stock	73	–	–	73
Proceeds from issuance of long-term debt, net	365	56	–	421
Net increase in short-term debt	170	293	217	680
Retirement of long-term debt	(705)	(68)	(339)	(1,112)
Dividends paid on common stock	(558)	–	–	(558)
Dividends paid to parent	–	(340)	340	–
Changes in advances from affiliates	–	(205)	205	–
Contributions from parent	–	12	(12)	–
Other financing activities	(5)	15	1	11
Net cash (used) provided by financing activities	(660)	(237)	412	(485)
Cash provided (used) by discontinued operations				
Operating activities	–	145	46	191
Investing activities	–	(190)	(9)	(199)
Financing activities	–	(5)	(241)	(246)
Net increase in cash and cash equivalents	5	9	7	21
Cash and cash equivalents at beginning of year	–	14	20	34
Cash and cash equivalents at end of year	$5	$23	$27	$55

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Results of operations for an interim period may not give a true indication of results for the year. In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Summarized quarterly financial data was as follows.

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made Results of operations for an interim period may not give a true indication of results for the year The first quarter of 2005 included $31 million recorded for estimated severance expense for workforce restructuring and implementation of an automated meter reading

(in millions except per share data)	First[a][b]	Second[a][b]	Third[a][b]	Fourth[a][b]
2006				
Operating revenues	**$2,223**	**$2,298**	**$2,776**	**$2,273**
Operating income	**268**	**210**	**557**	**274**
Income from continuing operations	**85**	**19**	**283**	**127**
Net income (loss)	**45**	**(47)**	**319**	**254**
Common stock data				
Basic earnings per common share				
Income from continuing operations	**0.34**	**0.08**	**1.13**	**0.51**
Net income (loss)	**0.18**	**(0.19)**	**1.27**	**1.01**
Diluted earnings per common share				
Income from continuing operations	**0.34**	**0.08**	**1.12**	**0.51**
Net income (loss)	**0.18**	**(0.19)**	**1.27**	**1.01**
Dividends declared per common share	**0.605**	**0.605**	**0.605**	**0.610**
Market price per share				
High	**45.31**	**45.16**	**46.22**	**49.55**
Low	**42.54**	**40.27**	**42.05**	**44.40**
2005				
Operating revenues	$2,051	$2,079	$2,743	$2,295
Operating income	237	119	539	325
Income from continuing operations before cumulative effect of change in accounting principle	103	2	457	159
Net income (loss)	93	(1)	450	155
Common stock data				
Basic earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.42	0.01	1.84	0.64
Net income (loss)	0.38	(0.01)	1.82	0.62
Diluted earnings per common share				
Income from continuing operations before cumulative effect of change in accounting principle	0.42	0.01	1.84	0.64
Net income (loss)	0.38	(0.01)	1.81	0.62
Dividends declared per common share	0.590	0.590	0.590	0.605
Market price per share				
High	45.33	45.83	46.00	45.50
Low	40.63	40.61	41.90	40.19

[a] Operating results have been restated for discontinued operations

[b] Certain amounts have been reclassified to conform to current period presentation

initiative at PEF; the second and fourth quarters of 2005 included reversals of estimated severance expense of $13 million each quarter. The second quarter of 2005 included a $141 million charge related to postretirement benefits for employees participating in the voluntary enhanced retirement program (See Note 16A). The second quarter of 2006 includes a $91 million impairment charge to our synthetic fuels assets and a portion of our coal terminal assets (See Notes 8 and 9). The 2006 and 2005 amounts were restated for discontinued operations (See Note 3).

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

Years ended December 31 (in millions, except per share data)	2006	2005[a]	2004[a]	2003[a]	2002[a]
Operating results					
Operating revenues	**$9,570**	$9,168	$8,053	$7,470	$7,115
~~Income from continuing operations~~	~~**514**~~	~~721~~	~~673~~	~~771~~	~~546~~
Net income	**571**	697	759	782	528
Per share data					
Basic earnings					
Income from continuing operations	**$2.05**	$2.92	$2.78	$3.25	$2.51
Net income	**2.28**	2.82	3.13	3.30	2.43
Diluted earnings					
Income from continuing operations	**2.05**	2.92	2.77	3.24	2.50
Net income	**2.28**	2.82	3.12	3.28	2.42
Assets	**$25,701**	$27,062	$26,014	$26,207	$24,366
Capitalization					
Common stock equity	**$8,286**	$8,038	$7,633	$7,444	$6,677
Preferred stock of subsidiaries – not subject to mandatory redemption	**93**	93	93	93	93
Minority interest	**10**	36	29	24	10
Long-term debt, net[b]	**8,835**	10,446	9,521	9,693	9,522
Current portion of long-term debt	**324**	513	349	868	275
Short-term debt	**–**	175	684	4	695
Total capitalization	**$17,548**	$19,301	$18,309	$18,126	$17,272
Other financial data					
Return on average common stock equity (percent)	**7.05**	8.91	9.99	11.07	8.44
Ratio of earnings to fixed charges	**2.08**	2.11	2.23	2.06	1.61
Number of common shareholders of record	**61,920**	64,899	67,638	70,159	72,792
Book value per common share	**$32.71**	$32.35	$31.39	$30.94	$28.73
Dividends declared per common share	**$2.43**	$2.38	$2.32	$2.26	$2.20
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	**48,770**	52,306	50,782	51,501	49,734
Nuclear	**30,602**	30,120	30,445	30,576	30,126
Combustion turbines/combined cycle	**11,857**	11,349	9,695	7,819	8,522
Hydro	**594**	749	802	955	491
Purchased	**14,664**	14,566	13,466	13,848	14,305
Total energy supply (Company share)	**106,487**	109,090	105,190	104,699	103,178
Jointly owned share[c]	**5,224**	5,388	5,395	5,213	5,258
Total system energy supply	**111,711**	114,478	110,585	109,912	108,436

[a] Operating results and balance sheet data have been restated for discontinued operations.
[b] Includes long-term debt to affiliated trust of $271 million at December 31, 2006, and $270 million at December 31, 2005, 2004 and 2003.
[c] Amounts represent joint owners' share of the energy supplied from the six generating facilities that are jointly owned.

We use ongoing earnings per share to evaluate our operations and to establish goals for management and employees. We believe this presentation is appropriate and enables investors to more accurately compare our ongoing financial performance over the periods presented. Ongoing earnings as presented here may not be comparable to similarly titled measures used by other companies. Reconciling adjustments for ongoing earnings per share to reported GAAP earnings per share are as follows.

Years ended December 31	**2006**	2005	2004
Ongoing earnings per share	**$2.58**	$3.31	$2.06
Contingent value obligations mark-to-market	**(0.10)**	0.03	0.04
Discontinued operations	**0.23**	(0.10)	0.35
Impairments and one-time charges	**(0.29)**	–	–
Loss on debt redemption	**(0.14)**	–	–
Postretirement and severance charges	–	(0.42)	–
Litigation settlement	–	–	(0.12)
Reported GAAP earnings per share	**$2.28**	$2.82	$3.13

Contingent Value Obligation Mark-To-Market

In connection with the acquisition of Florida Progress Corporation, we issued 98.6 million contingent value obligations (CVO). Each CVO represents the right of the holder to receive contingent payments based on after-tax cash flows above certain levels of four synthetic fuels facilities purchased by subsidiaries of Florida Progress Corporation in October 1999. The CVOs are debt instruments and, under GAAP, are valued at market value. Unrealized gains and losses from changes in market value are recognized in earnings. Since changes in the market value of the CVOs do not affect our underlying obligation, we do not consider the adjustment a component of ongoing earnings.

Discontinued Operations

The operations of businesses that have been sold or are in the process of being sold are reported as discontinued operations, and therefore we do not view these activities as representative of our ongoing operations. Our discontinued operations include CCO; Rowan and DeSoto; Winchester Energy; Progress Telecom, LLC; Dixie Fuels; Progress Materials, Inc., Coal Mining, and Progress Rail.

Impairments and One-Time Charges

In May 2006, we announced that we had idled our synthetic fuels facilities. Due to the idling of these facilities, we performed an impairment test of all synthetic fuels facilities and other related long-lived assets during the second quarter of 2006. Based on the results of the impairment test, we recorded impairment charges. These charges represent the entirety of the asset carrying value of our synthetic fuels intangible assets and facilities, as well as a portion of the asset carrying value associated with the river terminals at which the synthetic fuels facilities are located. We do not believe this impairment is representative of our ongoing operations.

Due to the disposition plans relating to PVI's nonregulated generation facilities, we evaluated previously recorded state net operating losses for potential impairment during the second and fourth quarters of 2006. Based on the results of these evaluations, we impaired the state net operating losses by recording a valuation allowance for state net operation losses. We do not believe this impairment is representative of our ongoing operations.

Loss On Debt Redemption

In November 2006, the Parent redeemed the entire outstanding $350 million principal amount of its 6.05% Senior Notes due April 15, 2007, and the entire outstanding $400 million principal amount of its 5.85% Senior Notes due October 30, 2008. In December 2006, the Parent repurchased, pursuant to a tender offer, $550 million, or approximately 53.0 percent, of the aggregate principal amount of its 7.10% Senior Notes due March 1, 2011. Due to the nonrecurring nature of this loss, we do not believe it is representative of our ongoing operations.

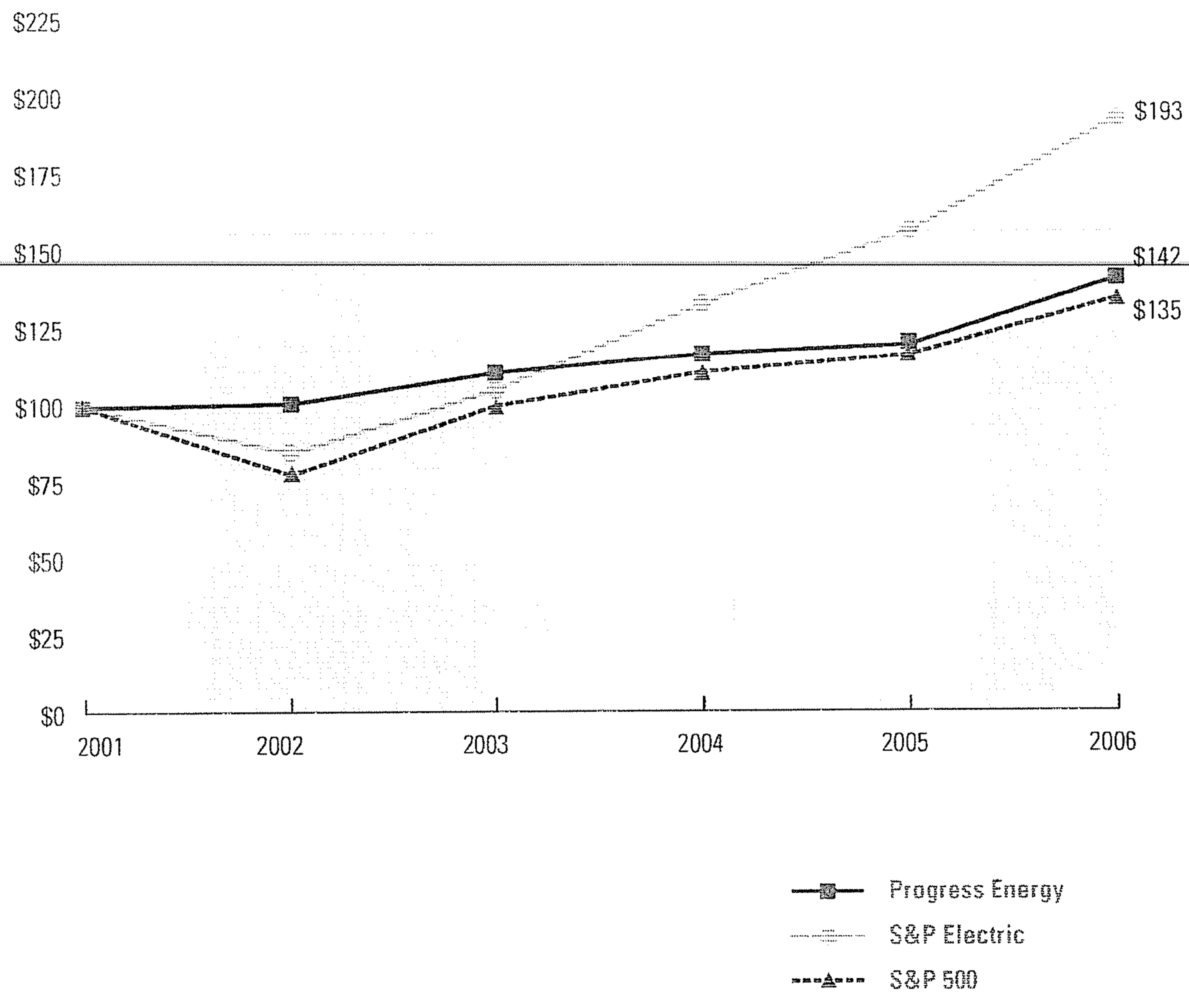
Postretirement and Severance Charges

As part of our cost-management initiative, we approved a workforce restructuring in February 2005, which resulted in a reduction of approximately 450 positions. In addition to the workforce restructuring, the cost-management initiative included a voluntary enhanced retirement program, in which 1,450 eligible employees elected to participate. In connection with this initiative, we incurred charges related to estimated future payments for severance benefits that will be paid out over time. Due to the nonrecurring nature of the charge, we do not believe it is representative of our ongoing operations.

Litigation Settlement

In June 2004, our subsidiary Strategic Resource Solutions Corp. reached a settlement agreement in a civil suit and recorded a corresponding settlement charge. We do not believe this settlement charge is representative of our ongoing operations.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN* AMONG PROGRESS ENERGY, INC., S&P 500 STOCK INDEX AND S&P ELECTRIC INDEX



Measurement Period (Fiscal Year Covered)	2001	2002	2003	2004	2005	2006
Progress Energy, Inc.	$100	$101	$111	$117	$120	$142
S&P Electric Index	100	85	105	133	157	193
S&P 500 Index	100	78	100	111	117	135

*$100 invested on 12/31/2001 in Stock or Index Including reinvestment of dividends Fiscal year ending December 31

Notice of Annual Meeting

Progress Energy's 2007 annual meeting of shareholders will be held May 9, 2007, at 10 a.m. in the Mahaffey Theater at the Progress Energy Center for the Arts in St. Petersburg, Fla. A formal notice of the meeting with a proxy statement will be mailed to shareholders in early April.

Transfer Agent and Registrar Mailing Address

Progress Energy, Inc.
c/o Computershare Trust Company
250 Royall Street
Canton, MA 02021
Toll-free phone number: **1.866.290.4388**

Shareholder Information and Inquiries

Obtain information on your account 24 hours a day, seven days a week by calling our stock transfer agent's shareholder information line. This automated system features Progress Energy's common stock closing price, dividend information and stock transfer information. Call toll-free **1.866.290.4388**.

Other questions concerning stock ownership may be directed to Progress Energy's Shareholder Relations by calling **919.546.3014** or by writing to the following address:

Progress Energy, Inc.
Shareholder Relations
410 S. Wilmington Street
Raleigh, NC 27601-1849

Stock Listings

Progress Energy's common stock is listed and traded under the symbol PGN on the New York Stock Exchange (NYSE) in addition to regional stock exchanges across the United States.

Shareholder Programs

Progress Energy offers the Progress Energy Investor Plus Plan, a direct stock-purchase and dividend-reinvestment plan, and direct deposit of cash dividends to bank accounts for the convenience of shareholders. For information on these programs, contact Computershare or the company.

We also offer online access to shareholder accounts via the Internet. To obtain online access to your shareholder account, go to computershare.com to register. If you have access to Progress Energy's annual report at your address, and do not want to receive a copy for your shareholder account, please call our transfer agent, Computershare, toll-free at **1.866.290.4388** to discontinue receiving annual reports by mail.

Dividend-reinvestment statements, tax documents and proxy material, including the annual report, can be electronically delivered to shareholders. Electronic delivery provides immediate access to proxy material and allows Internet voting while saving printing and mailing costs. To take advantage of electronic delivery of documents, go to computershare.com, log in to your account, select Electronic Shareholder Communications and follow the instructions.

Securities Analyst Inquiries

Securities analysts, portfolio managers and representatives of financial institutions seeking information about Progress Energy should contact Robert F. Drennan, Jr., vice president, Investor Relations, at the corporate headquarters address or call **919.546.7474**.

Additional Information

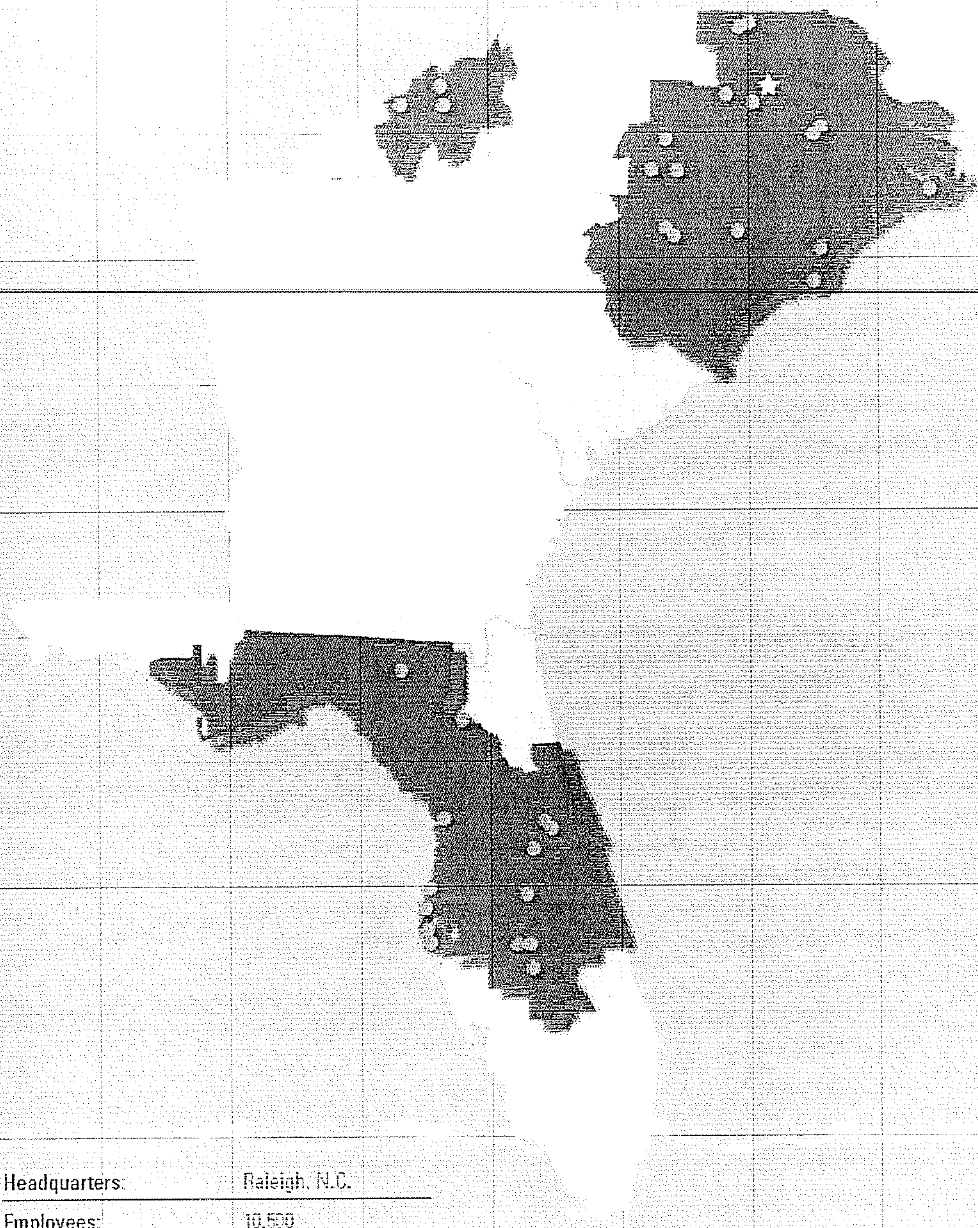
Progress Energy files periodic reports with the Securities and Exchange Commission that contain additional information about the company. Copies are available to shareholders upon written request to the company's treasurer at the corporate headquarters address.

This annual report is submitted for shareholders' information. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

NYSE Certifications

Because Progress Energy's common stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made that annual certification to the NYSE as of June 8, 2006. In addition, we have filed with the Securities and Exchange Commission, as exhibits to our Annual Report on Form 10-K for the year ended December 31, 2006, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes-Oxley Act of 2002 regarding the quality of our public disclosure.

PROGRESS ENERGY AT A GLANCE



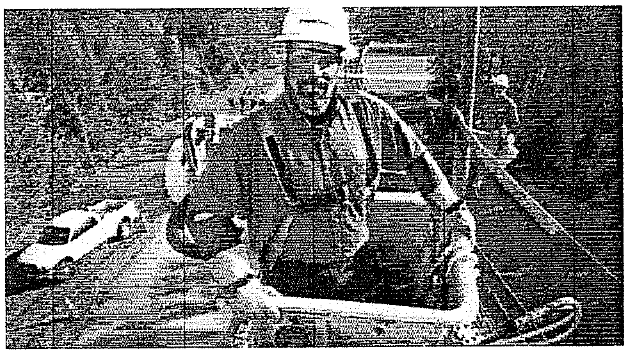
Headquarters:	Raleigh, N.C.
Employees:	10,500
Customers:	3.1 million
Service Territory:	54,000 square miles

☆ Progress Energy Corporate Headquarters

Operating Plant Locations

Progress Energy Regulated Service Area

Photo on back cover: Julio Mulkay, lineman



Progress Energy

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