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Delta Research Co.

312.467.0145
312.467.7051 fax
10 West Hubbard
4th Floor
Chicago, IL 60610

June 10, 1997

Mr. Robert A. Irvin
General Manager
Systems Operations Unit
Duquesne Light Company
411 Seventh Avenue
Pittsburgh, PA 15219

Dear Mr. Irvin,

We are writing to request copy of your RFP for 150 MW firm power.

Please send RFP to

Tom Pelsoci
Managing Director
Delta Research Co.
10 W. Hubbard St. 4 Floor
Chicago IL 60610

Thank you.

Tom Pelsoci

Post-it® Fax Note 7671	Date 6-16-97 # of pages ▶ 1
To FAYE	From SANDY
Co./Dept. SKADDEN, ARPS	Co. DLCO
Phone # 202-371-7071	Phone # 412-393-6253
Fax # 202-371-7939	Fax # 412-393-8647

CMS Marketing, Services and Trading

FROM: Donald Lechnar

FAX: 517-768-2071

VOICE: 517-768-2065

TO: Robert Irvin

FAX: 412-393-8647

MESSAGE:

Dear Mr. Irvin,

I am responding to the Duquesne Light reverse RFP for up to 500MW, as described in the June 9, 1997 issue of Megawatt Daily. Could you forward a copy of the RFP to the address listed below?

Donald Lechnar
CMS Marketing, Services and Trading
One Jackson Square
Suite 1060
Jackson, MI 49201-2277

Thank you,

Don Lechnar

Don Lechnar

Eastern Power Corporation
610 Chadds Ford Drive Suite #8
Chadds Ford, PA 19317
Tel: 610-388-3642
Fax: 610-388-0394

Fax Cover Page

To: Robert Irvin
From: S. Peter Ford
Fax Number: 412-393-8647
Date: 6/9/97
No. Pages: 1 (including cover page)
Subject: Duquesne RFP (reverse)

The following fax is intended for the person whose name appears at the top of this cover page. This fax may contain material of a confidential nature and should not be viewed by anyone not listed above. If you have trouble with the reception of this document or cannot locate the person specified above please contact us at the address marked at the top of this page.

Message:

Dear Mr. Irvin,

Please fax me a copy of the Request for Proposals mentioned in todays edition of MW Daily. My fax # (610) 388-0394.

Thanks.

The attached press release announcing Duquesne's Request For Proposal to sell firm power was sent over PR Newswire's national circuit to more than 2,000 newspapers, wire services, magazines and broadcast points across the U.S., the Investors Research Wire which serves more than 100,000 terminals in the worldwide financial community, and to all appropriate trade publications in the electric utility industry.

The firm capacity and energy to be sold will become available as Duquesne's present retail customers begin to choose to purchase the energy portion of their electric service from an electricity supplier other than Duquesne. The purpose of the solicitation and sale to the highest bidder is to determine the value in the marketplace of one-year and eight-year firm power.

NEWS

Duquesne Light
411 Seventh Avenue
Pittsburgh, PA 15219

CONTACT: Terri Glueck
(412) 393-4060

FOR IMMEDIATE RELEASE

Duquesne Light Company
Firm Power Sale

PITTSBURGH, June 6, 1997 - Duquesne Light Company, a subsidiary of DQE, Pittsburgh, PA is offering to sell at wholesale (i) 50 MW of firm electrical capacity and energy ("firm power") for a term of one year, commencing January 1, 1998, and (ii) at least 100 MW, but not more than 500 MW, of firm power for a term of eight years, commencing January 1, 1998. Bids are due June 26, 1997. Purchasers may submit bids to purchase all or part of the firm power, subject to a 2 MW minimum bid. Purchasers may vary their power schedules between 50% and 100% of the MW contract amount in any hour. Each calendar year, purchasers must take or pay for the power at a 75% annual capacity factor. Provided Duquesne receives sufficient qualifying bids, Duquesne commits to sell 50 MW for one-year and at least 100 MW for eight years to the highest bidder(s) on a $/MWH basis.

Duquesne will be obligated to make available the full contract amount to the purchaser, subject to the capacity factors described above. If Duquesne cannot deliver the power scheduled by the purchaser through dispatch of its generation or the purchase of power from third parties, the purchaser will have the right to secure replacement power and Duquesne will reimburse the purchaser for any increased costs.

The winning bidder(s) may use this wholesale purchase to supply customers in the wholesale market or the needs of their retail customers in Duquesne's or other PA utility's proposed retail access pilot program(s) this fall and later during the full phase-in of retail access.

The RFP is available on-line at www.soc_dlco.lm.com. Interested parties may receive a copy of the RFP by writing to: Robert A. Irvin, General Manager, System Operations Unit, Duquesne Light Company, 411 Seventh Avenue, Pittsburgh, PA 15219 or requesting a copy by facsimile: (412) 393-8647.

###

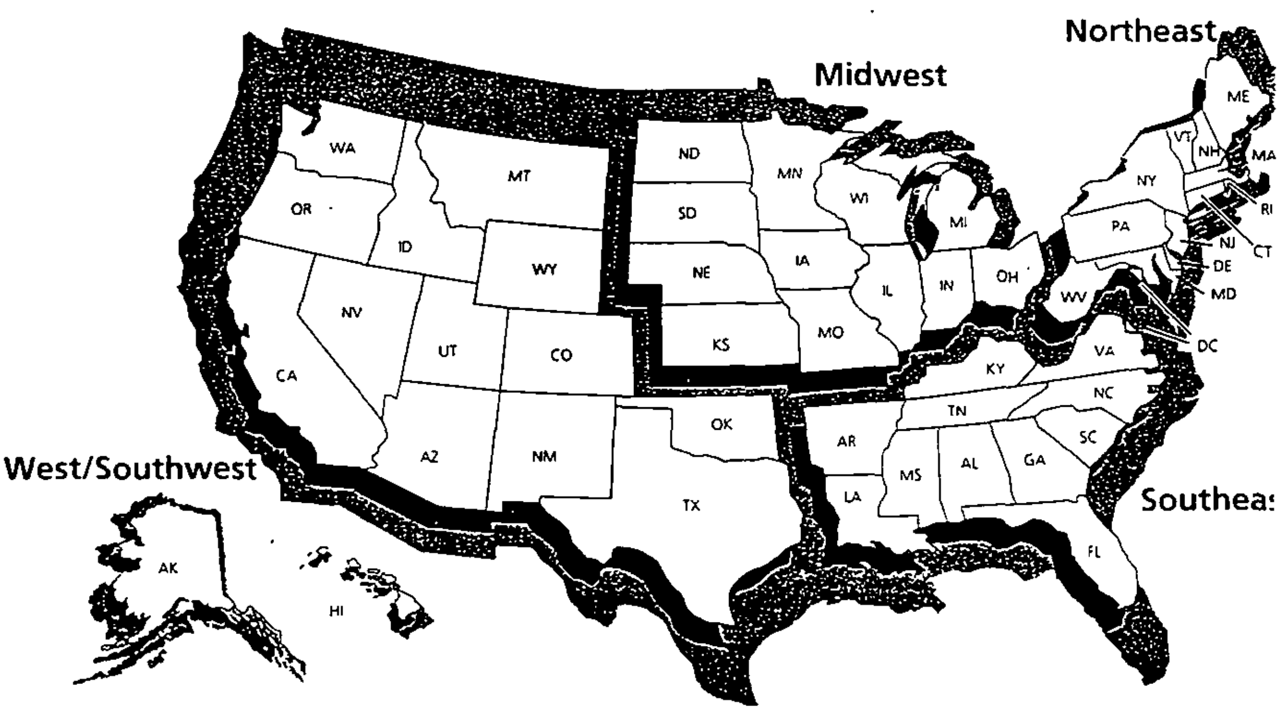
NATIONAL NEWSLINES

US1 is PR Newswire's premier national circuit, giving you access to more than 2,000 newspapers, wire services, magazines and broadcast points across the U.S. The Investors Research Wire, with points served listed on page 58, serves more than 100,000 terminals in the worldwide financial community and is included with US1 at no additional charge. All appropriate trade publications in your industry as listed on page 47, also receive your transmission free of charge.

(NewsLine Listing begins on page 9.)

US2 is PR Newswire's basic national circuit, serving some 1,500 news points. It also includes the Investors Research Wire at no additional charge, as well as appropriate trade publications, as listed on page 47.

(NewsLine Listing begins on page 16.)



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McGraw-Hill Publications (27)
Palatine
Food & Beverage Network
Peoria
Journal Star

INDIANA
Anderson
Herald-Bulletin
Bloomington
Herald-Times
Columbus
Republic
Elkhart
Truth
Evansville
Courier • Press
WEHT-TV • WTVW-TV
Ft. Wayne
Journal-Gazette
News-Sentinel
WANE-TV • WKJG-TV
WPTA-TV
Gary
Post-Tribune
Goshen
Goshen News
Hammond
Times
Indianapolis
News • Star • AP • UPI
WTTV-TV • WISH-TV
WRTV-TV
Network Indiana (68 outlets)
WIBC-AM • WKLR-FM
Business Journal
Indiana Business Magazine
Lafayette
Journal & Courier
Richmond
Palladium-Item
South Bend
Tribune
Terre Haute
Tribune-Star

IOWA
Cedar Falls
Futures World News
Cedar Rapids
Gazette
Davenport
Quad City Times
Des Moines
Register • AP
Business Record
KCCI-TV • WHO-TV
WOI-TV • KJJY-AM/FM
KIOA-AM • KRNT-AM
WHO-AM
Waterloo
Waterloo Courier

KANSAS
Wichita
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Lexington
Herald-Leader
Louisville
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Kentucky Radio Network
Owensboro
Messenger-Inquirer
Paducah
Sun

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Frederick
News-Post

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(Business Radio Network)
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Herald & Daily Mail
Morning Herald
Prince George's County
Journal
Rockville
Montgomery Journal • NASD

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Globe • Herald
AP • UPI • Reuters
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Christian Science Monitor
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Sportstyle
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Pennwell Publishing
Computer Design
Computer Graphics World
Solid State Tech
Type World
Brockton
Enterprise
Framingham
Middlesex News
IDG: Computerworld
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Cape Cod Times
Lawrence
Eagle-Tribune
Lowell
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Standard-Times
Newton
Cahners Publications:
Business Research Group
CPI Purchasing
Datamation
Design News
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EDN Products
Electronic Business Buyer
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Test & Measurement World
Traffic Management

Newport Beach
Orange Cty Business Journal
Ontario
Inland Valley Daily Bulletin
Oxnard
Star
Palmdale
Antelope Valley Press
Palm Springs
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Pasadena
Star-News
Riverside
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Sun
San Diego
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The North County Times
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Business Journal
Daily Transcript
Shadow Broadcasting
KSDO-AM • KCLX-FM
KYXY-FM • KIFM-FM
KPOP-AM • K102-FM
KKLQ-FM/AM • KOGO-AM
San Gabriel Valley
Daily Tribune
Business Journal
San Pedro
News-Pilot
Santa Ana
Orange County Register
Orange County NewsChannel
Santa Barbara
News-Press
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Outlook
Solana Beach
Blade-Citizen
Thousand Oaks
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Daily Breeze
Venice Marina
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Ventura
Counbty Star
Victorville
Daily Press
West LA
Independent
Westchester Ladera
Observer

Chilton Publishing
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Drug Store News
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Business Week
Other publications served:
Adweek
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COLORADO
Boulder
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Greenwich
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Meriden
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Register
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Wilton
Simba Publications
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Nightly Business Report
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Bloomberg Latin America
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South Florida Business Journal
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Securities Industry Daily
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Cards International
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Chain Drug Review
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Frequent Flyer
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Maxwell's Official Airline Guide
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Redford • Rochester
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Oakland Tech News
Tech Center News
US Auto Scene:
Metro Edition
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Agence France-Presse
Crain's Detroit Business
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Ward's Automotive Pubs.
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Fargo Forum
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Daily Journal of Commerce
Business Journal
Salem
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Bloomsburg
Press-Enterprise
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Express-Times
Erie
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WJET-TV • WSEE-TV
Ft. Washington
Today's Spirit
Montgomery Newspaper Group
Greensburg
Tribune-Review
Harrisburg
Patriot • Evening News
State Capitol Newsroom
Pennsylvania Cable Network
Radio Pennsylvania Network
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Intelligencer Journal
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New York Times Bureau
City Hall Newsroom
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Business Week
The Inquirer News Tonight
Philadelphia Business Journal
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Metro Traffic
Shadow/Express Broadcast Svcs.
Fairchild Pubs. (10 pubs.)
Pittsburgh
Post-Gazette
Pittsburgh Tribune-Review
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Post-Intelligencer • Times
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Microsoft News Network.
Asia Pacific Journal
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Marples Business Newsletter
Puget Sound Business Journal
Washington CEO
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Capital Times • State Journal
Wisconsin Radio Network
WKOW-TV • WMTV-TV
Milwaukee
Journal Sentinel
Daily Reporter • AP
WISN-TV • WITI-TV
WTMJ-TV
WOKY-AM/WMIL-FM
WTMJ-AM/WKTI-FM
Business Journal
Community Newspapers
Oshkosh
Northwestern
Racine
Journal Times
Rhinelander
WJFW-TV
Sheboygan
The Press
Wausau
The Daily Herald

WYOMING
Cheyenne
Tribune Eagle

IRW

AAL Distributors
ABB Financial Services
ABC Bank
ABD Securities
Abel/Noser Corp.
Abelow, Ihasz
ABN Bank
ABN Securities
Abraham & Sons Asset Mgt.
Abu Dhabi Investment Authority
Acacia Mutual Life Insurance
Access Securities
Account Management Corp.
Acorn Asset Management
Acre Street Investments
Adams, Harkness & Hill
Addison & Associates
Adler & Shaykin
Advanced Investment Mgt.
Advest
Aegis Holdings
Aegon Investment Management
Aetna Life & Casualty
AGF Asset Management
AIG Investment Advisors
Aim Advisors
Airlie Group
AJ Investments
Albert Cohen Partners
Alef Bank
Alex. Brown & Sons Inc.
Alexander & Alexander
Alexander Hamilton Life Ins.
Alfa Mutual Insurance
Allen & Company
Allendale Insurance
Alliance Capital Management
Allianz Investment
Allied Group Securities
Allison-Williams
Allstate Life Insurance
Alpha Management
Alpine Associates
Amalgamated Life Insurance
Ambac
Amber Marsh
American Asset Management
American Capital Management
American Express
American *Family Mutual Ins.*
American Fidelity Assurance
American General
American Investors Life
American Life & Casualty
American Mutual Life
American National Bank
American National of Chicago
American Securities
American Stock Exchange
Amerindo Investment Advisors
Amerisure
Ameritrust
Amica Mutual Insurance
Amoskeag Bank
Amro Finance
Amsouth Bank
Amster & Co.
Andco Securities
Anderson & Strudwick
Andover Securities
Angelo, Gordon & Co.
Anhalt/O'Connell
The Anschutz Corporation
Aon Advisors
Arcanum One Partners
Arco Management
Ardsley Partners
Argos Partners
Arkwright Mutual Insurance
Armen Partners
Arnhold & S. Bleichroeder
Asahi America
ASB Capital Management
Aspen Capital
Associated Capital Investors
Atlanta Capital Management
Atlantic Mutual
Avatar Associates
Axe Houghton Management
Back Bay Advisors
Ballentine Capital Management
Baltimore Street Capital
Banc One Asset Management
Banc One Securities
Bank Cantrade
Bank Julius Baer
Bank Leumi
Bank of America
Bankers Trust
Banque Bruxelles Lambert
Banque Indosuez
Banque Nationale de Paris
Banque Pallas
Banyan Securities
Barclay Investments
Barclays de Zoete Wedd
Baring America Asset Mgt.
Barnett Brokerage Services
Baron Capital
Bardett & Company
Bass Brothers Enterprises
Bateman Eichler, Hill Richards
Batterymarch Financial Mgt.
B.C. Christopher Securities
BEA Associates
Beacon Hill Partners
Bear, Stearns
Beck Mack & Oliver
Becker Inc.
Beekman Capital
Belforte Group
Bell Buckle Securities
Benchmark Asset Management
Benefit Capital Management
Berg Capital
Bernard L. Madoff & Associates
Bessemer Trust Company
Bitterroot Capital
Blackstone Group
Blair (William) & Co.
Bliss Securities
Blunt Ellis/Kemper Group
Boatman's Trust Company
Bodri Inc.
Boettcher & Company
The Boston Company
Bradford (J.C.) & Co.
Branch Cabell & Company
Brean Murray, Foster Securities
Brinson Partners
Broadgate Asset Mgt.
Brookhaven Capital
Brown (Alex.) & Sons
BT Brokerage
Bull & Bear Equity Advisers
Burns Fry Hoare Govett
Burns Fry Ltd.
Burns Pauli & Company
Burgess Capital
Business Men's Assurance
Butcher & Singer
Buttonwood Associates
Cable Howse & Ragen
Cadence Capital Mgt.
CALPERS
Calvert Group
Cambridge Investments
Campbell Advisors
Cantor Fitzgerald & Co.
Capital Group
Capital Holding Corp.
Capitol Life Insurance
Capitoline Investment Services
Carillon Advisers
Carlyle Group
Carnegie Capital Management
Carolan & Company
Cary Grant & Company
Caxton & Company
Cazenove & Company
CECO Financial Serfvices
Chancellor Capital Management
Chapdelaine
Charles Schwab & Co.
Chase Investors Management
Chicago Asset Management
Chicago Corp.
C&S Investment Advisors
Chubb Group
Citibank/Citicorp
C.J. Lawrence, Morgan Grenfell
Clayton Brown & Associates
CL GlobalPartners Securities
Cohen & Steers Capital
College Retirement Equities Fund
Colonial Management Assoc.
Colonial Penn Group
Combined Insurance
Commerzbank
Connecticut National Bank
Conner Capital
Conning International
Constitution Capital Mgt.
Continental Asset Management
Continental Bank
Continental Capital Management
Cook Inlet Investment Mgt.
Cooke & Bieler
Core States Investment Advisors
Cornerstone Management
County NatWest Securities
Cowen & Company
Crabbe-Huson Company
Craig-Hallum
Craigie, Inc.
Cramer & Company
Credit Commercial de France
Credit Suisse
Cresvale International
Criterion Investment Mgt.
Crosby Securities
CRT Securities
Cruttenden & Company
Cumberland Associates
Dai-Ichi Securities
Daiwa Int'l Capital Management
Daiwa Securities
Dakota Partners
Dallas Securities
Dalton, Greiner, Hartman
Darien Capital Management
Dean Witter Reynolds
Delaware Management
Denali Capital Management
Denver Investment Advisors
de Paolis & Company
Deutsche Bank
Dewey Square Investors
Dickinson (R.G.) & Co.
Dickstein & Co.
Dietche & Field Advisors
Dillon, Read & Company
Dimensional Fund Advisors
DLM Holdings
Dodge & Cox
Dominion Securities
Donaldson Lufkin & Jenrette
Dorsey, Wright & Associates
Drake Capital Securities
Dresdner Bank Investment Driehaus Securities Corporation
Dreyfus Corp.
Duke Management Company
Duncan Capital Management
Dunlevy & Co.
Durkee Capital Advisors
E.I. du Pont de Nemours
Eagle Asset Management
EastWest Capital Management

Exhibit RAI-6
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(A.G.) & Sons
estment Advisors
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irement Sys. of Texas
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Capital Management
: Capital Management
: Securities
: Law Fund Mgt.
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Capital Partners
Insurance Group
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d Investors
& Co.
Holding Co.
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d Programs
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ann & Leff Associates
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Frank & Co.
Russell Trust Co.
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an Securities Co.
an Welwood
, Revy Investment Co.
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way Investment Advisors
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. [illegible] & Co.
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dman, Sachs & Co.

Gordon & Co.
Gordon Capital
Gotham Capital
Gradison & Co.
Gramercy Capital Management
Granite Capital
Grantchester Securities
Great Lakes Capital
GRE Capital Management
Greenwich Capital Markets
Greenwich Partners
Griffin Capital Management
Gruber & McBaine Capital Mgt.
Gruntal & Company
Guardian Life
Guild Investment Management
Guzman & Company
Halcyon Investments
Hambrecht & Quist
Hanifen, Imhoff
Hanson Investment Management
Harper McLean
Harris Bretall Sullivan & Smith
Harris Securities
Harris Trust
Hartford Life Insurance
Harvard Management
Haven Capital Management
Havey, Youngman Associates
Hawthorne Associates
Hayne, Miller & Farni
H.C. Wainwright
Hellman, Jordan Mgt.
Hemisphere Partners
Henderson Brothers
Herzog, Heine, Geduld
Hickey Financial Services
Highland Capital Management
Hilliard, Lyons
Hintz, Holman, Hecksher
Hoenig & Company
Home Capital Services
Hopper Soliday
Houlihan Lokey Howard & Zukin
Hovey, Youngman Associates
Howard Weil LaBouisse
Howe, Barnes Investments
Huff Investment Management
Hughes Investment Management
Husic Capital Management
Hyperion Capital Management
IBM Retirement Funds
IDS Financial Services
Industrial Bank of Japan
Infiniti Investment Group
Instinet
Institutional Capital Corp.
Insurance Company of the West
Interallianz
International Capital Access
International Pacific Securities
Interstate/Johnson Lane
Intervest Securities
Investek Capital Management
Investment & Capital Mgt.
Investors Management Group

Ivory & Sime/Jamison Eaton & Wood
JMC Capital Management
J.P. Maguire Investment Adv.
J.W. Seligman & Co.
James Capel & Company
James (Raymond) & Associates
Janus Capital
Jefferies & Co.
Jennison Associates Capital
Jesup, Josephthal
John Hancock Advisers
Johnson Investment Counsel
Jones & Associates
Jones (Edward D.) & Co.
Jundt Associates
Kaufman (Henry) & Co.
Kayne, Anderson
Kealhofer, McQuown & Vasicek
Keefe Bruyette & Woods
Keely Investment Corp.
Kellner, DiLeo & Co.
Kemper Financial Services
Kennedy Capital Management
K Associates
Keystone Investment Mgt.
Kinnard & Co.
Kingsley, Jennison, McNulty & Morse
Kirkpatrick, Pettis, Smith, Polian
Kirr, Marbach & Co.
Kirschner Sacks Capital
Kleinwort Benson
Ko Securities
KWS Equities
Kuwait Investment Authority
Ladenburg, Thalmann & Co.
Lafayette Square Partners
Lancaster Financial
Laterman Associates
Lazard Freres
Lazard & Laidlaw.
Thomas H. Lee Company
Legg Mason Wood Walker
Lehman Ark Management
Lehman Management
Leominster Inc.
Lexington Management
L.H. Alton & Co.
Liberty Capital Management
Liberty Mutual Insurance
Lind Waldock & Company
Lindquist Enterprises
Lloyds Bank
Lodestar Group
Loomis Sayles & Co.
Lord, Abbett & Company
Lovett, Underwood, Neuhaus & Webb
Luther King Management
Lutherna Brotherhood
Lynch & Mayer
Mabon Nugent & Company
Malabar Capital Limited
Manchester Growth Fund
Mandrakos Capital Management
Manning & Napier Advisors

Manufacturers Hanover Trust
Manulife Int'l Inv. Mgt.
Marathon Asset Management
Marcus Schloss
Marine Investment Management
Marinvest
Marion Bass Securities
Mark Partners
Marque Millennium Group
Massachusetts Mutual Life
McCowan Associates
McCullough Andrews & Capiello
McDonald & Company
McGlinn Capital Management
McIntosh Hamson Hoare Govett
McKenzie, Walker Inv. Mgt.
Mellon Bank
Mercantile Bank
Merchants Insurance Group
Mercury Securities
Merrill Lynch
Merrill Lynch Asset Management
Mesirow & Company
MJK Associates
MJT Advisors
Mid-Continental Securities
Midland Montague
Midlantic National Bank
Midwest Advisory Services
Midwest Stock Exchange
Miller Johnson & Keuhn
Miller & Schroeder Financial
Miller Tabak & Hirsch
Milton Partners
Minorco
Mitchell Hutchins Asset Mgt.
Mitsubishi
Mitsui
MJT Advisors
MMS International
Montgomery Asset Management
Montgomery Securities
Monument Capital Management
Moody's Investors Service
Moore Capital Management
Moors & Cabot, Inc.
Morgan (J.P.) Investment Mgt.
Morgan (J.P.) Securities
Morgan Keegan & Co.
Morgan Grenfell Capital Management
Morgan Guaranty Trust Co.
Morgan Stanley & Co.
Morgens, Waterfall
Mountain Gate Partners
Muriel Siebert & Company
Mutual of New York
Mutual of Omaha
Nagreen Investments
NASD
National Fin'l Services Corp.
Nationwide Financial Services
NCM Capital Management
NCNB
Nesbitt Thomson
Neuberger & Berman
New Amsterdam Partners

New England Asset Management
New Japan Securities
New York & Foreign Securities
New York Life Insurance
New York Stock Exchange
Newhard, Cook
Newsouth Capital Management
NFJ Investment Group
Nicholas-Applegate Capital Mgt.
Nikko Capital Management
Nolan (W.J.) & Company
Nomura Securities
Northern Capital Management
Northern Trust Company
Northwestern Mutual Life
Norwest Investment Services
Oak Associates
OCI Anstalt
Oeschle International Advisors
Ohio Casualty Group
Ohio Public Emp. Retirement Sys.
Old Kent Bank
Oppenheimer & Co.
Oppenheimer Mgt. Corp.
Oscar Gruss & Son
Osterweis Capital Management
Pacific Century Advisors
Pacific Enterprises
Pacific Equity Management
Pacific Investment Management
Pacific Mutual Life Insurance
PaineWebber
Paresco
Paribas Corp.
PCM International
Peninsula Capital
Penn Mutual Life
Pennsylvania Investments
People's Bank
Peregrine Capital Management
Perkins Capital Management
Perpetual Investment Mgt.
Phoenix Capital Markets
Pilgrim Group
Pioneering Management Corp.
Piper, Jaffray & Hopwood
Pitcairn
Portola Group
Potomac Capital
Precision Asset Management
Presbyterian Board of Pensions
Prescott, Ball & Turben/Kemper
Presidio Management
Price (T. Rowe) & Associates
Prime Capital Management
Primerica
Printon-Kane
Prospect Advisors
Provident Capital Management
Provident Mutual Life
Prucap Management
Prudential Life Insurance
Prudential Securities
Putnam Management Co.
Quantitative Asset Management
Quest Advisory Corp.
RCM Capital Management
R.J. Steichen & Co.
Raffensperger, Hughes & Co.
Ragen MacKenzie
Rainier Investment Management
Rainwater Inc.
Rauscher, Pierce & Refsnes
Raymond James & Associates
Regal Capital Company
Regent Investors Services
Reich & Tang
Reimer & Koger Associates
Reliance Insurance
Republic National Bank
G.W. Ringoen & Company
Robert W. Baird & Co.
Robertson, Stephens
Robinson-Humphrey Company
Rochdale Securities
Rockefeller & Company
Rocker Partners
Rodman & Renshaw, Inc.
Roll & Ross Asset Management
Roney & Company
Rosenberg Capital Management
Rosewood Financial
Ross Capital Management
Rotan-Mosle, Inc.
Rothschild Asset Management
Ruggles Capital Management
Runnells Enterprises
Frank Russell Trust Co.
R.W. Corby & Company
St. Paul Companies
Salomon Brothers
Salomon Brothers Asset Mgt.
Sandler Capital Management
Sanford C. Bernstein & Co., Inc.
San Francisco Partners
Sanwa Capital Management
Sasco Capital
Sass (M.D.) & Associates
Schaenen Wood & Associates
Scotia McLeod (USA) Inc.
Scott & Stringfellow
Scudder, Stevens & Clark
Security Capital Management
Security Pacific Bank
Security Research
Seidler Amdec Securities
Seligman & Company
Sentinel Asset Management
Shawmut Bank
Shearson Lehman Brothers
Sherwood Securities
Shields Asset Management
Marcus Schloss & Co.
Siebel Capital Management
Sierra Capital
SIT Investment Associates
Smith Barney, Harris Upham
Smith Breeden Associates
Smith Graham Investment Mgt.
Smith, Moore & Company
Society National Bank
Soros Fund Management
Southeast Bank
Southtrust Securities
Sovran Capital Management
Spear Leeds & Kellogg
Stamford Company
Standard & Poor's
Standish, Ayer & Wood
State Farm Insurance
State Street Bank & Trust
Stein Roe & Farnham
Steinberg Asset Management
Steinhardt & Partners
Stephens Inc.
Sterling Capital Management
Sterling & Yorke Securities
Sterling Financial Group
Sterne, Agee & Leach
Stewart & Associates
Stifel Nicholas Company
Stuka Associates
Sumitomo Bank
Summit Investment Corp.
Sutro & Co.
Swiss Bank Corporation
Target Investors
Teachers Insurance
& Annuity Association
Templeton, Galbraith
& Hansberger
Texas Commerce Bank
Thomas Green/San Diego
Securities
Thomas H. Lee Company
Thomson McKinnon Asset Mgt.
Tinicum Partners
Todd Investment Advisors
Traveler's Investment Mgt. Co.
Trinity Capital Advisors
Troster Singer
Trust Company of the West
Tucker Anthony & R.L. Day, Inc.
Tudor Investment Corp.
Twelve Oaks Ltd.
Twentieth Century Fund
Tyndall-Newport Mgt. Corp.
UBS Securities
Union Bank
United Fidelity Insurance
United Jersey Bank
United Services Advisors
Unum
USAA Investment Management
U.S. Steel & Carnegie Pension
Fund
U.S. Trust Company
U.S.F. & G. Investment Services
V.P. Securities
Valarian Associoates
Van Clemens Co.
Van Deventer & Hoch
Van Eck Securities Corp.
Van Kampen Merritt Inc.
Van Kasper & Company
Venad Management
Vanguard Capital
Variable Annuity Life
Vaughan, Nelson, Scarborough
Vining Sparks
Victor Teicher & Co.
Volpe Welty & Company
Waddell & Reed
Wagner, Stott & Company
Walter Frank & Company
Warburg (S.G.) & Co.
Ward & Associates Asset Mgt.
Wasserstein Perella & Co.
Weber, Hall, Sale & Associates
Wedbush Morgan Securities
Wedge Group
Wedgewood Capital Mgt.
Weeden & Company
George Weiss & Associates
Weiss, Peck & Greer
Wellington Management
Wells Fargo Bank
Wertheim Asset Management
Wertheim Schroder & Co.
Wessels, Arnold & Henderson
West Highland Capital
West Valley Financial Mgt.
Westchester Capital Mgt.
Western Reserve Capital Mgt.
Westminster Management Group
Weston Capital Management
Westwood Management Corp.
Wheat, First Securities
Wheat Investment Advisors
Whitehouse & Moore
WIG Securities
Wilke/Thompson Capital Mgt.
William Blair & Company
William R. Woodruff & Co.
Wilson Foster & Co.
Windsor Financial Group
Wood Gundy
Wood, Struthers & Winthrop
Wm. Woodruff & Co.
Worthen Banking
Wright Investors' Service
W.R. Lazard & Co.
Yaeger Securities
Yamaichi Securities
Yasuda Life America Capital Mgt.
Zachs Investment Research
Ziv Investment Co.

TRADE PUBLICATIONS

A vital component of many communications strategies is reaching industry-specific newspapers, newsletters and periodicals. A story placement in one of your industry's well-read publications goes a long way toward educating the readers about your product or service. At **no additional charge** for any release that moves over our wire, PR Newswire provides extensive coverage of the significant publications in your industry. We also contact editors on a continuous basis to review their areas of editorial interest and tailor our lists so that your releases reach the editors managing that particular beat.

Exhibit RAI-6
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Trade Publications

ADVERTISING/MARKETING
- Advertising Age
- Adweek
- Green Marketing Report
- Premium/Incentive Business
- TA Report

AEROSPACE/AVIATION
- Aerospace Daily
- Aerospace Electronic Business
- Aerospace Review
- Airports
- Air Transport World
- Aviation Daily
- Aviation International
- Aviation Ground Equipment Market
- Aviation Production Engineering
- Aviation Times
- Aviation Week & Space Technology
- Defense Aerospace Business Digest
- Helicopter News
- International Aviation
- Military Space
- Regional Aviation Weekly
- Space Business News
- Space Commerce Bulletin
- Space Markets
- Space Station News
- Speednews
- The Weekly of Business Aviation
- World Aviation Directory

AUTOMOTIVE/ TRANSPORTATION
- Automotive Electronics Journal
- Automotive Fleet Magazine
- Automotive Industries
- Automotive News
- Automotive & Transportation Interiors
- Commercial Carrier Journal
- Crain's Tire Business
- Motor Age
- Motor Trend
- Owner Operator
- Power Transmission Design
- Road & Track
- Traffic Management
- Urban Transport News
- U.S. Rail News
- Ward's Auto World
- Ward's Automotive Reports
- Ward's Engine Update

BUILDING/ENGINEERING
- Architectural Record
- Builders Kitchen & Bath
- Building Design & Construction
- Building Supply Home Centers
- Construction Claims Monthly
- Construction Data & News
- Construction Equipment
- Construction News
- Consulting Specifying Engineer
- Contract
- Contractor
- The Daily Journal
- Daily Pacific Builder Dodge
- ENR
- Highway & Heavy Construction Products
- House Plans
- Interiors
- International Construction Week
- Kitchen & Bath Business
- Multi-Housing News
- National Home Center News
- Professional Builder & Remodeler
- Supply House Times

BUSINESS AND FINANCE
- Accounting Today
- American Banker
- American Marketplace
- Atlanta Business Chronicle
- Bank Letter
- Bank Loan Report
- Bank Marketing International
- Bank Systems & Technology
- Banker & Tradesman
- Banking Week
- Barron's
- Best Insurance Management Reports (BIMR)
- BestWeek
- Best's Review
- Bond Buyer
- Bond World
- Boston Business Journal
- Bowman's Accounting Report
- Branch Automation News
- Branch Manager
- Business Insurance
- Business Week
- Card News
- Cards International
- Charlotte Business Journal
- Cincinnati Business Courier
- Cincinnati Business Reporter
- Claims
- Columbus Business First
- Contingencies
- Corporate EFT News
- Corporate Financing Week
- CPA Managing Partner Report
- CPA Marketing Report
- CPA Personnel Report
- CRA/HMDA Update
- Crain's New York Business
- Crain's Cleveland Business
- Crain's Detroit Business
- Denver Business Journal
- Dowline
- EFT Report
- Electronic Payments Int'l
- Equities
- European Banker
- Fair Employment Report
- Finance & Commerce
- Financial Services Report
- Financial Services Week
- Financial Times of London
- Financial Weekly
- Fitch Investors Service
- Forecasts & Strategies
- Fortune
- German Economic News Service
- Going Public: The IPO Reporter
- Hartford Business Journal
- Indianapolis Business Journal
- Independent Agent
- Industry Week
- Inside Mortgage Capital Markets
- Inside Mortgage Finance
- Insight
- Insurance Marketing Int'l
- Insurance Record
- International Accounting Bulletin
- Investment Dealers' Digest
- Investor's Business Daily
- Item Processing Report
- Jacksonville Business Journal
- Japan Economic Journal
- Journal of Accountancy
- Journal of Commerce
- Journal of Retail Banking
- Life Insurance Selling
- Life Insurance International
- Los Angeles Business Journal
- Louisville Business Journal
- Memphis Business Journal
- Mergers & Acquisitions Report
- Middle-Market Focus
- Milwaukee Business Journal
- Money
- Money Management Letter
- Moody's Investor's Service
- Mortgage-Backed Securities Letter
- Nashville Business Journal
- National Mortgage News
- National Underwriter
- Orange County Business Journal
- Orlando Business Journal
- Private Banker International
- Private Placement Letter
- Public Accounting Report
- Puget Sound Business Journal
- Retail Banking International
- Rough Notes (Insurance Sales Edition)
- Rough Notes (Property & Casualty Edition)
- S&P Compustat
- S&P Daily News Online
- S&P Marketscope
- San Diego Business Journal
- San Diego Daily Transcript
- San Francisco Business Times
- San Jose Business Journal
- Securities International
- Securities Trader's Monthly
- Securities Week
- SNL Securities
- Spokane Journal of Business
- Standard & Poor's
- Southern Banker
- The Accountant
- The Practical Accountant
- The World Bank Watch
- Today's CPA
- Toledo Business Journal
- Triad Business
- Triangle Business
- Underwriters Report
- United States Banker
- Wall Street Journal
- Washington Business Journals

CIO Magazine
Circuit Design
Circuits Assembly
Circuits Assembly Asia
Circuits Assembly Magazine
Circuits Manufacturing
Client /Server Computing
Client Server News
Client/Server Tools Bulletin
Common Carrier Week
Comm. Engineering & Design
Communication Week Int'l
Communications Business & Finance
Communications Daily
Communications Electronics
Communications Industries Report
Communications News
Communications of the ACM
Communications Systems Design
Communications Week
Compupress
Computable
Compute!
Compute!'s Gazette
Computer & Software Retailing
Computer Age-EDP Weekly
Computer Applications Journal
Computer Buyer's Guide and Handbook
Computer Chronicles
Computer Currents
Computer Daily News
Computer Design
Computer Digest
Computer Edge
Computer Entertainment News
Computer Exchange World
Computer Finance
Computer Gaming Review
Computer Gaming World
Computer Graphics World
Computer Industry Almanac
Computer Industry Daily
Computer Intelligence
Computer Letters
Computer Life
Computer Life (UK)
Computer Magazine
Computer Marketing & Distribution Report
Computer Reseller News
Computer Retail Week
Computer Security Institute
Computer Shopper
Computer Solutions
Computer Sources Magazine
Computer Sun Times
Computer Technology Review
Computer Telephony
Computer Trade Show World
Computer User
Computer Week (S. Africa)
Computer Weekly
Computer-Aided Engineering
ComputerCraft
Computers in Africa
Computers in Banking
Computers in Libraries
Computers Today on Television
Computerworld
Computing Australia
Computing Canada
Content Developer
Convergence
Corporate EFT Report
Crabb on Computers
Creative Strategies *Research International*
Dallas Computer Currents
Dallas/Fort Worth Technology
Daratech
Data Channels
Data Communications
Data Entry Awareness Report
Data News
Data Resources Management
Data Training
Data Warehousing Tools Bulletin
Database
DataBase Associates
Database Management
Database Products Reports
Database Programming & Des.
Datacom
Datacom Reader
Datamation
Dataquest
DBase Advisor
DBMS
Dealerscope
DEC Professional
DEC User
Delphi Report
Dempa Digest
Digital Kids
Design News
Digital Media
Digital News & Review
Digital Systems Journal
Digital Technology Report
Digital Video Magazine
Digital's Rdb World
Dist. Processing Product News
Distributed Computing
Distributed Systems Management Tools Bulletin
DMAX Information Services
Document Delivery World
Document Image 3 Automation
Document Image Update
DOS Resource Guide
Dr. Dobb's Journal
EDI News
EDN Asia
EDN Magazine
EDN Products & Careers
Education Computer News
EFT Report
Elect. Buyers' News Handbook
Elect. Trade & Transport News
Electronic Business Buyer
Electronic Buyers' News
Electronic Design
Electronic Engineering Times
Electronic Gaming News
Electronic Learning
Electronic Library
Electronic Mail & Micro Systems
Electronic Media
Electronic Messaging News
Electronic News
Electronic Packaging Production
Electronic Products
Electronica Oggi
Electronics
Electronics Weekly
Embedded System Programming
Engineering Automation Report
Engineering With Computers
Enterprise Communications
Enterprise Systems Journal
Entertainment Weekly (Multimedia section)
EOSIESD Technology
EPIC USA
Family Computing
Family PC
FCC Week
FDDI
Federal Computer Week
Fiber Datacom
Fiber Optics
Fiber Optics Directory
Fiber Optics Magazine
Financial Services Report
Firstfaxts
Forrester Research
Friday Holdings
Frost & Sullivan
GamePro
Gartner Group
Giga Information Group
Global Telecom
Global Telephony
Government Computer News
Graphic Arts Monthly
Graphic Detail
Group Computing Magazine
Hard Copy Observer
High Performance Computing Review
High Tech Hot Sheet
High Tech News (French Newsletter)
High Tech Notes
High Technology Careers
Home and Office Technology (HOT)
Home Electronic Entertainment
Home Office Computing
Home PC
HP Chronicle Newspaper
HP Professional
HPC Wire
Hum Magazine
IBM's Software Quarterly
I/O
I/S Analyzer
IBM Computer Today
ID Magazine
ID Systems
IDG News Network
IDP Reports
IEEE Computer Graphics & Applications
IEEE Design & Test of Computers
IEEE Engineering Management & Review
IEEE Expert
IEEE Micro
IEEE Network
IEEE Software
IEEE Spectrum
Imaging Magazine
Imaging World
Inc. Magazine
Inc. Technology
Industrial Communications
Industry.Net.
InfoCorp
InfoDB
Infomart Magazine
Infonetics Research
Informatica Oggi Mese (Italy)
Informatica Oggi Settimanale (Italy)
Information & Interactive Services Report
Information Industry Bulletin
Information Technology (French Newsletter)
Information Today
Information Week
Informatique Hebdo
Infoworld
Insurance Software Review
Integrated System Design
Intelligent Network News
Interactive Age (Online)
Interactive Catalog
Interactive Content
Interactive News Network
Interactive Week
Interactivity
InterAd
International Data Corp.
Internet Gazette
Internet Research
Internet World
Internet Week
InterNetwork
Intranet World
ISDN News
ISDN Newsletter
ISDN User
IW, The Management Magazine
IYM Software Review
JavaWorld Magazine
Journal of Electronic Engineering
Journal Of Electronics Industry
Journal of Information Systems Management
KidSoft
LAN Magazine
LAN Newsletter
LAN Reporter

TRADE PUBLICATIONS

CHEMICALS/PLASTICS
- Chemical Business
- Chemical Engineering
- Chemical & Engineering News
- Chemical Marketing Reporter
- Chemical Week
- CPJ Purchasing
- Modern Plastics
- PetroChemical News
- Plastics and the Environment
- Plastics News
- Plastics and Packaging
- Plastics Week
- Plastics World
- Rubber & Plastic News
- TWICE

DEFENSE
- Advanced Military Computing
- C41 Report
- Defense & Aerospace
- Defense Cleanup
- Defense Daily
- Defense Industry Report
- Defense Marketing Int'l
- Defense News
- *Defense Plant Waste News*
- Defense Technology Business
- Defense Week
- International Defense Review
- Jane's Defense Weekly
- Jane's NATO Report
- Military Space
- Mine Regulation Reporter
- Navy News and Undersea Tech
- Report on Defense Plant Wastes
- SDI Intelligence Report
- SDI Monitor
- Soviet Intelligence Review

ELECTRICAL/ELECTRONICS
- Architectural Lighting
- Circuits Assembly
- *Electronic Component News*
- Electronic Design
- Electronic Marketing News
- Electronics
- Electric Utility Week
- Electrical World
- Fiber Optics News
- Test & Measurement World

ENTERTAINMENT/ BROADCASTING

Complete details of PRN's exclusive EntertaiNet service can be found on page 98.

ENVIRONMENTAL

The following trades are included at no extra charge. For expanded environmental coverage, see page 113.

- Air Toxics Report
- Air/Water Pollution Report
- Asbestos Control Report
- Clean Water Report
- Ecology USA
- Environmental Health News
- Environmental Liability Monthly
- Green Marketing Report
- Greenhouse Effect Report
- Ground Water Monitor
- Hazardous Waste Business
- Hazardous Waste News
- HazMat Transport News
- HazTech News
- Indoor Pollution News
- Land Use Report
- Noise Regulation Report
- Nuclear Waste News
- Sludge
- Solid Waste Report
- *State Environmental Report*
- Superfund
- Toxic Materials News
- World Environmental Report

FOOD
- Baking & Snack Systems
- Baking Buyer
- Food Engineering
- Food Engineering International
- Food Service Equipment & Supplies Specialist
- Milling & Baking News
- World Grain

HEALTH/MEDICINE/BIOTECH
- American Baby
- *American Health Consultants*
- American Journal of Cardiology
- American Journal of Medicine
- *American Journal of Surgery*
- Applied Genetic News
- BioCentury
- Bio/Technology
- Biotech Daily
- Biotech Reporter
- Biotechnology Information Inst.
- Biotechnology News
- Biotechnology Newswatch
- Bioventure Stock Report
- Bio Venture View
- BioWorld Today
- Cancer and Genetics Report
- Cardio
- Childbirth
- Contact Lens Forum
- Contemporary Longterm Care
- Cutis
- Diagnostic Imaging
- Diagnostic Imaging Int'l
- Drug Store News
- Electronic News
- Emergency Medicine
- Environment, Safety & Health Series
- FDC Report "The Blue Sheet"
- FDC Report "The Green Sheet"
- FDC Report "The Gray Sheet"
- FDC Report "The Gold Sheet"
- FDC Report "The Pink Sheet"
- FDC Report "The Rose Sheet"
- First Year of Life
- Genetic Engineering News
- Genetic Technology News
- Health Care Competition Week
- Health Care Strategic Mgt.
- Health Grants & Contracts
- Health Industry Today
- Health Manager's Update
- Health News Daily
- Health Record
- Health Resources Publishing
- Health Tribune
- Health Week
- Healthy Kids Birth-3
- Healthy Kids 4-10
- Healthy Legislation & Regulation
- HLB Newsletter
- Hospital Materials Mgt.
- Hospital Medicine
- Hospital Patient Rel. Report
- Hospital Purchasing
- In Vivo
- Jenks Healthcare Business Rprt.
- Managed Care Law Outlook
- Managed Care Outlook
- MDDI Reports "Gray Sheet"
- Medical Advertising News
- Medical Liability Advisory
- Medical Tribune
- Medical Utilization Review
- Medical Waste News
- Medicine & Health
- Mental Health Law Reporter
- Mental Health Report
- Modern Healthcare
- Nursing Recruitment & Ret.
- Ophthalmology Management
- Optometric Management
- Pharmaceutical Daily
- Pharmaceutical Ventures
- Physicians Biotechnology
- Physicians Financial News
- Physicians Travel Meeting Guide
- Postgraduate Medicine
- Quality Control Reports
- Review of Optometry
- Scrip-World Pharmaceutical News
- TJFR Health News Reporter
- Urology
- Weekly Pharmacy Reports
- World Pharmaceutical Standards Review

HIGH TECHNOLOGY
- Aberdeen Group
- Access Magazine
- Access Monthly
- Access to Wang
- Accounting Technology
- Ad Age
- Ad Week
- Ad-Fax
- Advanced Imaging
- /AIXtra (UNIX)
- AI Expert
- Algorithmica
- America's Network
- Amiga World
- Andrew Seybold's Outlook on Communications and Computing
- Application Development Trend·
- Asahi Personal Computing
- Asian Communications
- Asian Electronic Union
- Atlanta Computer Currents
- ATM
- Australian Personal Computer
- Autocad World
- *Automatic I.D. News*
- Automatic Speech Recognition
- AV Video
- Aviation Week
- BackOffice Magazine
- Banking/Datacom Group
- Bay Area Computer Currents
- Beyond Computing
- BOC Week
- Boston Computer Currents
- Branch Automation News
- Broadband Networking
- Broadband Systems & Design
- Business Communications Revi
- Business Research Group
- Business Strategies
- BusinessTimes
- Byte Magazine
- C/D ROM Professional
- C31
- Cable Optics
- Cable-Telco Report
- CableWorld
- CADalyst
- Cadence
- CAD Report
- California Technology Stock L
- Campus-Wide Info Systems
- Canadian Computer Reseller
- Canopus Research
- Card News
- CBT Directions
- CD ROM Today
- CD ROM World
- CED Magazine
- Cellular Intergration
- Chance: New Directions *for Statistics/Computing*
- Chilton's Electronic Component News
- Chip-Talk

TRADE PUBLICATIONS

LAN Technology Magazine
LAN Times
Land Mobile Radio News
Laser Focus World
Laser Report
Library Software Review
Light Wave
Link Resources Corp.
Link Up
Local Area Networks Newsletter
Lookout Point Interactive
Lyra
M.D. Computing
Mac Home Journal
MAC TV
Macintosh Update
MacTech Magazine
MacUser
MacWeek
Macworld
Management InfoCorp.
Managing Automation
Manufacturing Systems
Marketing Computers
MarketPro
Memory Card Systems & Design
Meta Group
Metropolitan Area Networks
Micro Publishing Report
Microsoft Systems Journal
MicroTimes
Midrange Systems
MIPS World
Mobile Office
Mobile Phone News
Mobile Product News
Mobile Products Europe
Mobile Satellite News
Modem Office Technology
Monash Information Services
Monash Software Newsletter
Mondo 2000
Monitor
Multichannel News
Multimedia Business Report
Multimedia Daily
Multimedia Monitor
Multimedia Review
Multimedia Week
Multimedia Wire
Multimedia World
National Report On Computers
& Health
Natvaridem
NCR Connection
.net The Internet Magazine (UK)
NETFAX News
NetGuide
Netware Solutions
Netware Technical Journal
Network Computing
Network Computing Magazine
Network Computing News
Network Management Systems
Network Technical Services
Network Week (U.K.)
Network World

Networking Management
New Media
News & Review
Newsbytes News Network
NextREVIEW
Object-Oriented Tools Bulletin
OCLT Systems & Services
Office World News
Officemation Product Reviews
Online Magazine
Online Review
Online Tonight
Open Computing
Open Systems News
Open Systems News
Oregon Technology Newsletter
OS/2 Developer
OS/2 Magazine
Packaged Software
Patricia Seybold Group
PC Computing
PC Dealer
PC Digest/Microsystems Report
PC Digest/Peripherals Report
PC Entertainment
PC Gamer
PC Graphics & Video
PC Graphics Report
PC Laptop
PC Letter
PC Magazine
PC News
PC Novice
PC Plus (U.K.)
PC Press
PC Shopping Show Inc.
PC Street Price Index
PC Techniques
PC Today
PC TV Productions
PC User
PC Week
PC Week Labs
PC World
PC World Online
PC+
Peak Computing Magazine
Personal Computer Network
Personal Electronic News
Personal Systems
Personal Workstation
Perspective
Phone+
PhotoMedical
Photonics Spectra
PickWorld
Plastic Optical Fiber
Popular Electronics
Portable Computing
Portland Computer Bits
Presentation Solutions
Presentations
Printed Circuit Fabrication
Probe Research
Publish
Puget Sound Computer User
Quick Response News

R & D Magazine
Radio Communications Report
Release 1.0
Report on AT&T
Report on IBM
Reseller Management
Reseller World
Reseller World Magazine
Retail Info Systems News
Retailing Tech. & Operations
RF Designs
RS/Magazine
Run
Rural Telecom
Russian Fiber Optics &
Telecom Magazine
Satellite Communications
Satellite News
Scientific Computing
& Automation
Selling Networks
Semiconductor International
Sensors Magazine
Service News Magazine
Seybold Report on
Desktop Publishing
Seybold Report on
Publishing Systems
Silicon Graphics World
Silicon Valley Business (TV)
Smart Magazine
SNA Communications Report
Softpub Resource Letter
Software Developer & Publisher
Software Digest Ratings Report
Software Industry Bulletin
Software Industry Report
Software Magazine
Software Marketing Journal
Software Trader
Solid State Technology
SPARC
STACKS
State Telephone Reg. Report
Storage Systems Today
Strategy Network Consulting
Sun Expert
Sun Observer
Sun World
Superconductor Week
Systems & Network Integration
Systems Integration
Systems Integration Business
& Marketing
T E & M's Telecom Asia
Technical Employment News
Technical Enterprises
Technologic Partners
Technology & Media
Telco Competition Report
Telecom Data Report
Telecom Market Letter
Telecom Strategy Letter
Telecommunications
Telecommunications Alert
Telecommunications
Billing Reports

Telecommunications Magazine
Telecommunications Reports
Telecommunications Reports Int'l
Telecommunications Reports
Wireless News
Telecommunications World
Teleconnect
Telephone Industry Directory
Telephone News
Telephony
Test & Measurement World
The A: Drive
The Age
The ATM Report
The Bishop Report
The Bulletin
The Cobb Group
The EFT Sourcebook
The HP Chronicle
The Local Netter Newsletter
The Long-Distance Letter
The MAP Netter
THE NET
The Operator
The OSI Netter
The PC Netter
The Red Herring
The Sun Observer
Token Perspective Newsletter
TR Wireless News
Training Electronics
Tribuna Informatica
TV Technology
Twice
Unigram.X
Unisys World
Unisys World 4 Europe
UNIX Review
Upgrade Magazine
Upside Magazine
User Friendly Computer News
& Reviews
User Friendly Reseller Resourse
VAR Business
VAX Professional
Venture Finance
Via Satellite
Videogame Advisor
Video Marketing Newsletter
Video Marketing Surveys
& Forecasts
VideoNews International
Video Pro
Video Technology News
Video Toaster User
ViewText
Virtual Reality Report
Voice Information
Voice Technology News
Wafer News Confidential
Wall Street Computer Review
Wang in the News
Washington Technology
Washington Trade Report
Web Developer
Web Review
Web Techniques

Windows Magazine
Windows Sources
Windows Watcher
WIRED
Wireless Design & Development
Wireless Magazine
Wireless Product News
Wireless Telecommunications
WordPerfect for Windows Magazine
WordPerfect Magazine
Workgroup Technologies
Workstation for HP/Apollo
World Satellite Directory
X Business Group
Yankee Group
Zona Research, Inc.

INDUSTRIAL/DESIGN
Automation
Central Engineering
Contract Design
Design News
EDN Asia
EDN Magazine Edition
EDN News Edition
Industrial Distribution
Industrial Maintenance & Plant Operation
Interior Design
Machine Design
Material Handling Engineering
Materials Engineering
New Equipment Digest
Performance Materials
Plant Engineers
Product Design & Development

MINING/METALS
33 Metal Producing
American Machinist
American Metal Market
Casting Design & Application
Coal Outlook
Coal Statistics International
Coal Week
Coal Week International
Foundry Management & Technology
Heat Treating
Iron Age
Metal Center News
Metals Week
Mine Regulation Reporter
Welding Design & Fabrication
Welding Distributor

OIL/ENERGY
Coal & Synfuels Technology
Coal Outlook
Electric Utility Week
Energy Daily
Energy User News
Fusion Power Report
Gas Buyers' Guide
Gas Daily
Gas Daily's NG Magazine
Gas Storage Report
Gulf Coast Oil World
Inside Energy With Fed. Lands
Inside F.E.R.C.
Inside NRC
International Oil News
International Solar Energy Intelligence Report
Natural Gas Marketing
Northeast Oil World
Northeast Power Report
Nuclear Fuel
Ocean Oil Weekly Report
Offshore
Offshore Gas Report
Oil Daily
Oil & Gas Investor
Oil & Gas Journal
Oil and Gas Research
Oil, Gas & Petroleum Equipment
Oilgram News
Pipeline
PetroEnvironment
Platt's News Service & Pubs
Power
Power Engineering
Southwest Oil World
The Energy Report
The PT Distributor
U.S. Oil Week Publications
Western Oil Week

REAL ESTATE/ BUILDING MAINTENANCE
Commercial Property News
Commercial Record
Facilities Design & Management

RESTAURANTS/FOOD SERVICE
Marketplace
Nation's Restaurant News
Restaurant Hospitality
Restaurants & Institutions
The Foodservice Distributor

RETAILING
Chain Drug Review
Chain Store Age Executive
Discount Store News
Drug Store News
Garden Supply Retailer
Gift & Stationery Business
Hardware Age
HFD Weekly Home Furnishings
Home Fashions Magazine
Inside Retailing Newsletter
Mass Market Retailers
National Mall Magazine
Party Source
Retailing Tech. & Operations
Supermarket News

SAFETY
Emergency Preparedness News
Industrial Safety & Hygiene
Occupational Hazards
Occupational Health & Safety

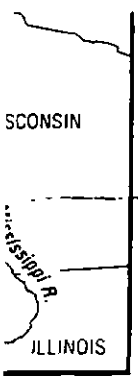
SCHOOLS/EDUCATION
Business Education World
Education Daily
Education Grants Alert
Education Monitor
Education of the Disadvantaged
Education of the Handicapped
Education Technology News
Education USA
Educational Marketer
Nation's Schools Report
Preschool Perspectives
Report on Education of the Disadvantaged
Report on Education Research
Report on Preschool Programs
School and College
School Child Care Report
School Law News
School Library Journal
School Tech News
Student Aid News
Vocational Training News

SPORTS/RECREATION
Action Sports Retailer
Golf Pro Merchandiser
Motorboat
Outdoor Retailer
Sail
Sporting Goods Business
Sportstyle
Tennis Merchandiser

TEXTILES/APPAREL
Apparel Merchandising
Children's Business
Daily News Record
Fashion Time Quarterly
FN Magazine
Footwear News
Home Textiles International
Home Textiles Today
Impressions Magazine
Nonwovens Markets
Nonwovens World
W
Women's Wear Daily

TRAVEL/TOURISM
Business & Incentives
Business Travel News
Corporate Travel
Hotels
Lodging Hospitality
Meeting News
OAG Travel Guide
Resorts & Incentives
Tour & Travel News
Travel Agent Magazine
Travel Agents Market Place
Travel Management Daily
Travel People
Travelage Caribbean
Travelage East
Travelage Europe
Travelage Midamerica
Travelage West
Travel Weekly

WOOD/PAPER
Forest Industries
Pulp & Paper
Pulp & Paper International
Pulp & Paper Week
World Wood



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by one university historian who offers
them an entertaining explanation:
Southerners suggest that some blacks s
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Exhibit RAI-7
Page 1 of 1

should be made that no one in the South
nies that the Confederacy was about s
ery and white supremacy. However,
facts of ante-bellum history are unmis
able: 1) It was the secession issue t
brought the country to war; 2) no on
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that issue substantively opposed slav
and white supremacy.

The federal government had no in
to abolish slavery during the ante-bel
era, and it was in fact a 45-year perio
grossly inequitable tariff policy that a
ally alienated the loyalty of Southern
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the legality of the institution where it
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power over the federal tariff, an ins
ment influencing the economic chara
of the nation far more profoundly tha
readily apparent from its ostensible
then as primary source of federal gov
ment revenues.

Although cotton was well known to
grown with slave labor, it was never l
cotted by any state that had a stake in
tile making; on the contrary, it was th
states that, by sustaining the tariff
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And most telling, the South's efforts at
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achieving emancipation by means o
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With conventional historians havin
tablished that the federal governn
went to war for the purpose of crusa
against slavery, those infernal South
ers are just sure to ask why, when
government leap-frogged all the meas
that might have culminated in an aboli
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clude that what the leadership of
North's great egalitarian society act
did was reveal itself as a collection of
mongers.

DENNIS G. SAUN
Columbia, Md.

* * *

Perhaps Nelson Winbush's claim
tens of thousands of blacks willi
fought for the Confederacy is exaggera
But whether, as his detractors prop
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Just Serve the Steak And Hold the Sizzle

Your May 22 Money & Investing ar
"More Firms Use Options to Gamble
Their Own Stock" was a great examp
what troubles many about the press.

ing. Dennis Meany, senior vice president of Duke/Louis Dreyfus, confirmed that all the personnel and trading assets of Duke/Louis Dreyfus will remain in the new company.

LADWP representatives said they assumed the alliance would be in place before the Federal Energy Regulatory Commission approved the merger of Duke Power and PanEnergy Corp. But the merger has accelerated, making the agreement more complicated, said Tom McGuinness, director of business development for LADWP. "We're asking the City Council for a little more time to verify Duke/Louis Dreyfus's commitment of personnel and resources is not affected by the merger."

McGuinness said his department is sure the merger will not affect the agreement. The combined Duke/PanEnergy will be bigger and stronger and the assets of Duke/Louis Dreyfus that made them so attractive to LADWP—the retail products and services, the people and the trading system—will remain in the new company. "We just need to make sure all the questions the City Council might ask are answered," he said.

DUQUESNE OFFERS 50-MW, 1-YEAR BLOCK AND 100- TO 500-MW BLOCK FOR 8 YEARS

Duquesne Light is offering to sell two blocks of firm capacity and energy: a 50-MW block for one year; and a block of at least 100 MW, but not more than 500 MW, for eight years. Contracts for both would begin Jan. 1, 1998.

Bids are due on Jun 26, 1997. The request for proposals is available on Duquesne's web site, at http://www.soc_dlco.lm.com. It can also be obtained by writing to: Robert Irvin, General Manager, System Operations Unit, Duquesne Light, 411 Seventh Ave., Pittsburgh, PA, 15219, or by fax at (412) 393-8647.

Interested parties may submit bids to purchase all or part of the power, subject to a 2-MW minimum bid. Buyers may vary their power schedules between 50% and 100% of the MW contract amount in any hour. However, in each calendar year, buyers must take or pay for the power at a 75% annual capacity factor.

Duquesne will deliver the power through dispatch of its generation or by purchases from third parties. If it cannot deliver, buyers have the right to find replacement power, and Duquesne will reimburse the buyers for any increased costs.

CALIFORNIA PARTIES TELL FERC 'MUST-RUN' TERMS FOSTER ANTICOMPETITIVE ACTIVITY

The California industry restructuring proposal's terms for "must-run" generation contracts could result in anticompetitive activity and undermine the new power exchange, independent power producers and industrial end-users protested to the Federal Energy Regulatory Commission. So-called must-run units are generation considered imperative for preserving system reliability.

"In particular, Must-Run Agreement B is likely to afford both the incentive and the opportunity for underbidding and predatory pricing in the PX," the joint filing warned. "This danger is most acute with regard to facilities owned by the investor-owned utilities, which will have admittedly unique incentives to depress PX prices during the period in which they are collecting competition transition charges."

Given the "serious concern to both competing generators and to ratepayers," the filing asked FERC to eliminate Agreement B as an option for an independent system operator-directed must-run contract. Agreement B is one of three alternatives proposed to the standard form Master Must-Run Agreement. The filing describes Agreement A as "basically an ancillary service call contract" for calling up generating units when needed that are not otherwise must-run units. Agreement C addresses units that are dedicated as reliability service providers and cannot otherwise participate in the competitive market.

The joint filing illustrates the "common concern of these disparate stakeholders in preserving the integrity of the market process," said the California Independent Energy Producers, California Cogeneration Council, California Manufacturers Assn. and the California Large Energy Consumers Assn.

FIRST INDUSTRIAL SIGNS ON TO SMUD'S NEW 'CUSTOMER TAILORED RATE' PLAN

The Sacramento Municipal Utility District approved its first new "customer tailored rate" last week, locking an industrial customer into an eight-year commitment to continue to purchase electricity from the municipal utility.

Chinet, manufacturer of paper plates, will be allowed to shop for electricity beyond its baseload needs according to a market index rate that includes a floor of 3.7 cents/kWh and a ceiling of 4.56 cents/kWh. These prices are included in the first year of the contract and escalate to 4.25 and 5.25 cents/kWh by the end of the eight-year contract period. Chinet reserves the right to cancel the contract if SMUD's annual average electricity costs exceed 6.5 cents/kWh after the five years of the contract.

SMUD was the first California utility to offer its customers direct access on June 1. The terms offered to Chinet are the utility's attempt to offer customers some choice in power supply, but still lock them into long-term power purchase arrangements. The contract is designed to allow SMUD to recover its fixed costs and is not less than SMUD's estimated marginal cost of energy generated or purchased on the wholesale market.

GAINESVILLE, FLA., OFFERS DISCOUNT RATE TO COMMERCIAL/INDUSTRIAL CUSTOMERS

The Gainesville, Fla., Regional Utilities Commission announced Friday it will begin offering new or expanding commercial/industrial customers a discount of up to 13%.

The new rate will be apply to retained, expanded or attracted load for companies with a demand of 100 kW or more on a case-by-case basis, which must be approved by the city commission.

The Flex Rate will provide a discount of up to 13% in exchange for a 10-year contract. The discount will apply during four years of the contract. The costs of the discount will be deducted from GRU's general fund transfer to the city.

CENTERIOR, AEP SEEK ADDITIONAL REVIEW OF CONRAIL ACQUISITION BY CSX/NORFOLK

Centerior Energy and American Electric Power are among parties seeking a more thorough regulatory review of plans by CSX Corp. and Norfolk Southern (NS) to

TRIBUNE REVIEW

Duquesne Light selling power on 'firm' basis

By Suzanne Elliott
TRIBUNE-REVIEW

Duquesne Light Co. said Friday it is selling some its capacity at the wholesale level.

While electric utilities sell excess capacity all of the time, the Duquesne Light offer is for "firm" power. This means if the utility can't deliver the power, then the utility or energy marketer who is purchasing the power can find an alternate source, and Duquesne Light will reimburse the purchaser for any increased costs.

"We are talking about selling any portion of two blocks of power," said Terri Glueck, a Duquesne Light spokeswoman. "The first block is on a one-year contract and can be anywhere from 2 megawatts to 50 megawatts. The second block of power is on an 8-year contract that's 100 megawatts, but not more than 500 megawatts."

Duquesne Light's annual capacity is 2,800 megawatts, she said. The utility has 580,000 customers in Allegheny and Beaver counties.

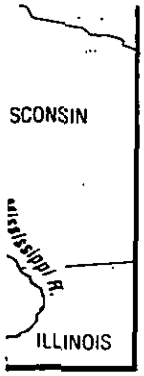
Glueck said this will be the first time the utility has sold power on the wholesale market on a "firm" power basis with a long-term contract.

"We think this is a very logical step in preparing for competition," she said. "In fact, many electrical utilities will probably be doing this in preparing for competition."

In November, the state General Assembly passed the Electric Generation Customer Choice Competition Act. This will open up competition between electric companies in Pennsylvania by 2001. It will begin being phased in by 1999.

In April, Duquesne Light's parent, DQE Inc., said it was merging with rival Allegheny Power System Inc. The $2.6 billion merger is expected to be complete in 1999.

DQE shares closed at $27.37½ yesterday, down 25 cents from Thursday's close.



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DENNIS G. SAUN
Columbia, Md.

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Just Serve the Steak
And Hold the Sizzle

Your May 22 Money & Investing ar
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what troubles many about the press.

Duquesne Light Company
Firm Power Sale

Duquesne Light Company, a subsidiary of DQE, Pittsburgh, PA has issued a Request For Proposal (RFP) for competitive bids for at least 150 MW of firm power which Duquesne Light Company is selling for periods of up to eight years.

The firm power will be sold to the highest bidder(s). The MW amounts will be 50 MW for one year beginning January 1, 1998 and an additional 100-500 MW for eight years beginning January 1, 1998.

The RFP is available on-line at www.soc-dlco.lm.com

Interested parties may receive a copy of the RFP by writing to:

Robert A. Irvin
General Manager
System Operations Unit
Duquesne Light Company
411 Seventh Avenue
Pittsburgh, PA 15219

DuquesneLight

DLCO RFP Frequently Asked Questions

Q1. Is Duquesne bringing a unit out of cold reserve to supply this sale?

A1. Duquesne has no present intention of bringing a unit out of cold reserve to supply this sale, althoughDuquesne may do so if the circumstances warrant.

Q2. What will be the source of the firm power to be sold?

A2. The power Sale Agreement attached to the RFP does not obligate Duquesne to supply the power from anyparticular source. Rather, the PSA commits Duquesne to supply the power as scheduled in accordance with thePSA. Duquesne will rely on owned generation or purchase power where appropriate to supply power scheduledunder the PSA.

Q3. Would bids which deviate from the bid floor price, length of purchase, or other terms and conditionsspecified in the RFP be considered?

A3. No. All bids must be in accordance with Section III, RULES FOR SUBMITTING BIDS of the RFP in order to be considered.

Q4. What dispatch flexibility is allowed with this offering (i.e. hourly dispatch, day-ahead election, etc.)?

A4. Scheduling information is provided in Article III, CONTRACT AMOUNT; CAPACITY FACTOR; SCHEDULING of the specimen Power Sale Agreement(s) included in the RFP package.

Q5. Is/are the product(s) being offered system firm or from designated resources?

A5. Please see the answer to A2.

Q6. On the subject of priority, is this sale(s) considered by Duquesne Light to be equivalent to Duquesnesnative load? If not, what priority is given to the offering(s)?

A6. The firmness of the power offered for sale is described in Articles III and IV of the Power Sale Agreementattached to the RFP.

Q7. Page 5 of the PSA defines conditions of "Force Majeure" as they apply to DLC but not the Buyer. Is it theintent of the PSA to excuse DLC's non-performance for events of Force Majeure without providing comparablerelief for Buyer's non-performance resulting from Force Majeure?

A7. The Force Majeure clause in Section 4.2 excusing the monetary penalty for non-delivery is applicable only to Duquesne because Duquesne is the only party under Section 4.2 that is liable for that non-delivery penalty.

Q8. What is the cost for firm and non-firm transmission of the purchased power to each of DLC's interfacepoints: APS, AEP, OE and Centerior?

A8. Duquesne Light Company's prevailing Open Access Transmission Tariff (OATT) provides for the followingrates:

(a) The long term firm and short term firm point-to-point transmission rate is $19,570/MW-YR (Schedule 7 ofOATT)

(b) The Annual Transmission Revenue Requirement For Network Integration Transmission Service is $49,855,404 (Attachment H of OATT). Duquesne Light Company's projected 1997 peak load is 2599MW.
(c) The "non-firm point-to-point transmission service" is a market driven, capped rate of (a) above.

Q9. Please describe the process and identify the criteria DLC will use to arrive at "mutual agreement" of adelivery point.

A9. Duquesne intends to arrange delivery points with the purchaser that are workable given the nature of thetransmission service that is procured. For example, if the purchaser seeks delivery of the power off-system usingpoint-to-point service, the purchaser may want to designate particular delivery points as "firm." Duquesneintends to work with the purchaser in arranging delivery points that would accommodate any such needs.

Q10. Under the proposed PSA the buyer is responsible for arranging and paying for transmission requiredacross the DLC system. Will DLC pay liquidated damages to the buyer for financial losses incurred by the buyerwhich result from required DLC transmission being unavailable or cut by DLC?

A10. No. The question relates to the quality of transmission service, which is governed exclusively by theFERC's Pro Forma Tariff. The Pro Forma Tariff does not provide financial penalties for interruptions of service. However, to address the concerns of the questioner, Duquesne will modify Section 6.1 of the PSA to read asfollows:

Delivery of Firm Power under this Agreement shall be at a point or points on the Duquesne Transmission System asmutually agreed by the Parties ("Points of Delivery"), provided, however, that in no event shall Duquesne beresponsible for the purchase of transmission service on the Duquesne Transmission System to effect such deliveryunless otherwise agreed by the Parties. "Duquesne Transmission System" shall mean the transmission facilities ownedby Duquesne at or above 69 kilovolts. If the Firm Power to be delivered consists in whole or in part of power purchased from third parties, Duquesne shall arrange and pay for the necessary transmission services to deliver such power to the Duquesne Transmission System. If receipt by Purchaser of Firm Power at specified Points of Delivery on the Duquesne Transmission System is not possible because of the curtailment or interruption of transmission service on the Duquesne Transmission System, (i) Duquesne shall deliver the Firm Power at such other Points of Delivery on the Duquesne Transmission System as are not subject to curtailment or interruption, or (ii) if there are no such available Points of Delivery on the Duquesne Transmission System, Duquesne shall deliver the Firm Power at such other Points of Delivery on the system of another transmission provider as are designated by Purchaser, provided that in such an instance, and notwithstanding subsection (b) hereof, Purchaser shall be responsible for any associated transmission service charges up to the Points of Delivery.

Q11. During the term of the 8-year contract does DLC envision the possibility of sourcing supply from thirdparties which will then be offered to the buyer at delivery points other than those on the DLC system?

A11. Duquesne will procure power from third parties to the extent it is economic to do so. Duquesne will deliversuch purchased power to the Duquesne system unless the purchaser requests, and Duquesne agrees, that it bedelivered at another delivery point. See the revisions to the PSA contained in the response to Question A2.

Q12. The CST and PSA do not provide adequate protection for either party to recover their marked-to-marketexposure in the event of a default. Would DLC amend the PSA to include the following default provision?

Default

In the event of a Default by either Party, the non-defaulting Party may terminate any or all Transactions under the Agreement upon the gAgreement upon the greater of (i) the minimum notice period required by law, or (ii) one business day's prior written notice to the defaulting Party, provided, however, that, in the case of bankruptcy or insolvency however evidenced, such Transactions may be terminated immediately without prior notice. Upon early termination, the non-defaulting Partyshall have the right to liquidate terminated Transactions by closing out such Transactions so that a Net Settlement)Payment equal to the sum of the differences between the market values over the contract values of each such terminated Transaction (which amounts shall be discounted to present value in a commercially reasonable manner) is due to the Buyer if the aggregate market value exceeds the aggregate contract value and to the Seller if the opposite is the case. Such net amount due shall be paid by the close of business on the business day following the date of termination. The non-defaulting Party may set-off or aggregate the foregoing with other amounts due between the Parties under the Agreement or any other agreement between the Parties, all of which shall be deemed a single agreement for purposes of close-out and set-off hereunder, to produce a single liquidated amount payable by one Party to the other. For purposes of this provision, a "Default" shall occur (a) when a Party files for protection or is the subject of a filing under the bankruptcy laws, becomes insolvent however evidenced, or has an unexcused failure of payment or other performance (including a failure of creditworthiness by a guarantor or credit support provider) which continues for more than two business days after a demand for such payment or for more than ten business days after a demand for such otherperformance, or (b) when (i) a default, event of default or other similar condition or event (however described) in respect of the defaulting Party or any credit support provider of the defaulting Party under one or more agreements or instruments relating to Specified Indebtedness of either of them (individually or collectively) in an aggregate amount ofnot less than ten million dollars ($10,000,000) which has resulted in such Specified Indebtedness becoming, or becoming capable at such time of being declared, due and payable under such agreements or instruments, before it would otherwise have been due and payable, occurs or exists, or (ii) a default by the defaulting Party or its credit support provider (individually or collectively) in making one or more payments on the date thereof in an aggregate amount of not less than ten million dollars ($10,000,000) under such agreements or instruments (after giving effect to any applicable notice requirement or grace period), occurs or exists. "Specified Indebtedness" means any obligation (whether present or future, contingent or otherwise, as principal or surety or otherwise) in respect of borrowed money. The "market value" means the remaining quantity of capacity and/or energy to be delivered times the market price per unit remaining to be delivered as determined in a commercially reasonable manner. The "contract value" means the value of the remaining quantity ofcapacity and/or energy to be delivered as determined in a commercially reasonable manner. Other amounts due betweenthe Parties under the Agreement or any other agreement between the Parties shall be determined in a commerciallyreasonable manner. Each Party reserves to itself all rights, set offs, counterclaims and other defenses to which it is ormay be entitled arising from or out of the Agr

A12. Duquesne does not understand the question. The eight-year Power Sale Agreement contains a SecurityAddendum that allows either party to recover its marked-to-market exposure in the event of a default. TheSecurity Addendum provides far more specificity as to these matters than does the paragraph attached to thequestion.

Q13. Will DLC amend the PSA to include conditions of Force Majeure that apply equally to Buyer including aprovision that entitles Buyer to Force Majeure relief in the event DLC transmission is cut or unavailable?

A13. The question expresses concern regarding the unavailability of transmission service, which is addressed inthe answer to Question No. 2. The question also suggests adding a force majeure provision that applies"equally" to purchaser. As explained in a previous answer, the only force majeure clause contained in the PSA isin Section 4.2 and it applies only to Duquesne because Duquesne is the only party liable under that section fornon-delivery penalties.

Q14. Will DLC amend Section II.3 (Triggering Events) of the Security Addendum by replacing "....If at any timeduring the Contract Term, (Duquesne's or Buyer's) senior debt securities are below Investment Grade..." with"...If at any time during the Contract Term (Duquesne's or Buyer's) senior debt securities are rated belowStandard & Poors BBB..."?

A14. Duquesne does not intend to modify the provision because it reasonably requires that more than onerating agency rate a party's debt at below investment grade before the provisions of the Security Addendum aretriggered.

Q15. Will DLC amend Section VI.1 (Delivery) of the PSA to list the specific points on the DLC Transmission System of which one or more would be selected for delivery by mutual agreement of the parties?

A15. The answer to Question 10 addresses the questioner's concerns regarding the availability of transmissionservice.

SUPPLIER SCHEDULING PROTOCOLS IN PILOT FILING

Supplier Scheduling

1. Background. DLC will work with Suppliers during the pilot to streamline protocols for scheduling and delivery of electricity to pilot customers. As described below, DLC's existing FERC-filed tariffs provide the basic structure and agreements that will govern the contractual relations with pilot Suppliers.

Suppliers will be required to provide, by 12:00 noon of the Thursday prior to the following week, a schedule of power deliveries for each hour of each day for the following week. This schedule will be used for informational purposes and will not give rise to scheduling charges or imbalance penalties. The purpose of the schedule is to address, in advance, any significant differences between the aggregate load projections of suppliers and those of the control area operator. If such significant differences do exist, the control area operator will inform the suppliers and attempt to reconcile the projections on a consensual basis.

The formal scheduling protocol will be for suppliers to submit day-ahead schedules in accordance with the procedures and requirements contained in FERC's pro forma tariff. The tariff also will govern any schedule changes. These schedules and schedule changes will be subject to scheduling fees and will be used for calculating energy imbalance fees.

The data available to Suppliers from meter reads and load profile estimates will be limited. Prior to commencement of the pilot, Duquesne will endeavor to make available to Suppliers historical information to assist them in projecting customer loads. As the pilot progresses and these data gathering and dissemination processes are standardized, the information available to Suppliers will allow them to project load for their customers with more accuracy. As both Suppliers and DLC gain more experience in projecting, scheduling and measuring aggregated Supplier retail loads, DLC is open to negotiating new protocols with Suppliers. Initially, however, the protocols are necessarily limited by the available data and the information transfer capabilities of DLC and Suppliers.

The Supplier will aggregate the load of all retail customers into a schedule to be implemented by DLC's Systems Operations Department to import the necessary power into the DLC control area. The schedule will be submitted by means of a standard form and will include the source control area, evidence of satisfactory transmission arrangements, a megawatt amount for each hour of the schedule period, and any NERC scheduling requirements.

R-00974104, R-00974104C0001-C0002

Duquesne Statement No. 7-R

Pgm 12/17/97
G. Grantz

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Robert A. Irvin

Contents:

Response to Intervenor Testimony Regarding
Transmission and Ancillary Services

REBUTTAL TESTIMONY OF ROBERT A. IRVIN

Q. Please state your name and business address.

A. My name is Robert A. Irvin and my business address is 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930.

Q. What is the purpose of your testimony?

A. To rebut the testimony of ENRON witness Lynn R. Coles dated November 7, 1997.

Q. Mr. Coles's testimony at page 3, line 7 questions the availability of firm and non-firm point-to-point service in addition to network transmission service. What is the availability?

A. Duquesne will make available point-to-point service to any eligible customer in accordance with FERC rules. I note, however, that for purposes of the pilot program, Duquesne, like most other Pennsylvania utilities, treated all participating customers as network service customers. I am not aware of any complaints regarding this treatment.

Q. Mr. Coles' testimony at p.3, line 13 recommends adoption of his "Pro Forma Supplier Tariff", his Exhibit 5, LRC-2. Do you agree with his recommendation?

A. No, because it is unnecessary and redundant. The matters covered by it are adequately covered elsewhere. For example, Section 2, Energy Delivery Service by the Electric Distribution Company ("EDC"), is covered by a supplier becoming a transmission customer under DLC's FERC OATT.

Section 3.2, Supplier License requires licensure by the Commission, which is already a PAPUC requirement as is compliance with Standards of Conduct, Section 3.3.

Section 3.5, Transmission Rights Outside the Control Area, appears to be mistitled but the right to transmit <u>within</u> the host control area is provided by a supplier becoming a Transmission Customer under DLC's OATT.

Section 4.1, Duty to Cooperate, is covered by ECAR rules.

Section 4.2.3, Daily Supplier Identification of Source of Supply Scheduling System Control and Dispatch Service, is covered by NERC scheduling rules.

Section 4.2.4, Supplier Supply Obligation, is covered under DLC's FERC OATT, Attachment G and/or Attachment K.

Sections 4.2.5, Energy Imbalance Service, Section 4.2.6, Other Ancillary Services, and Section 4.3.2, Payments for Energy Imbalance Service, are covered under DLC's FERC OATT, as amended.

Appendix A, Supplier Agreement Form, is covered by a supplier becoming a Transmission Customer under DLC's FERC OATT.

Q. Mr. Coles' testimony at p.3, line 19 recommends that charges to suppliers be reasonable and minimum contract periods should be reduced. What is your position?

A. DLC's charges to suppliers have been approved by FERC. I am not aware of any "minimum contract period", imposed by Duquesne, and DLC permits the supplier to change his ancillary service options from time to time.

Q. Mr. Coles' testimony at p. 6, line 19 states DLC requires "customers to purchase their own transmission service and three of the ancillary services. Suppliers should be allowed to obtain all necessary components of transmission for their customers." What is the reality?

A. Mr. Lahtinen's testimony describes Duquesne's position regarding ancillary services in more detail. As indicated in my direct testimony, however, Duquesne will allow suppliers to competitively procure ancillary services pursuant to the standards and restrictions contained in Order 888.

Q. Mr. Coles' testimony at p. 7, line 17 states that "DLC's approach by using the open access rate "deadband" of 1.5% and penalties for not meeting these tight requirements is wrong for the retail access situation." What is your position?

A. The requirements noted by Mr. Coles are FERC requirements. However, DLC requested, and FERC trial staff has agreed to a settlement under which, an energy imbalance option available to all suppliers which eliminates the $\pm$1.5% deadband and provides a settlement for energy imbalance based on DLC's System Lambda.

Q. Mr. Coles' testimony at p. 8, line 3 discusses DLC's provision to suppliers of estimated load shapes and notes that the customer's actual load shape may be different. What is your position?

A. DLC offers to provide to suppliers load patterns which may be representative of a customer's usage pattern under DLC's rates. However, once the customer becomes the responsibility of the supplier, the supplier assumes the responsibility for responding to the variations in that customer's load. DLC has no control over, or interest in, pricing arrangements or other terms and conditions between a supplier and his retail customer which could result in the customer changing his pattern of use from his pattern when he was a bundled tariff customer of DLC.

Q. Mr. Coles' testimony at p. 9, line 16 states "Since Duquesne calculates the hourly supplier obligation to serve a suppliers load, it is unfair to charge the supplier a penalty when the load obligation total determined by Duquesne does not match the actual system hourly load." Is this correct?

A. No. The supplier information which was made available at DLC's supplier conference on September 26, 1997 and which has been and is available on the internet places the responsibility on the supplier for projecting and scheduling into DLC's control area the aggregate hourly load requirements of the supplier's customers. Thus, Duquesne does not "calculate the hourly supplier obligation" for purposes of scheduling power to its retail customers.

Q. Mr. Coles' testimony at p. 11, line 4 states "Furthermore, FERC has explicitly provided for scheduling, dispatch and control and energy imbalance services for wholesale and state-authorized retail transactions as part of Open Access transmission tariffs. These arrangements provide the foundation for energy imbalance service to Suppliers and customers under Pennsylvania' retail access." What is your comment?

A. I agree with Mr. Coles' statement. The procedures which DLC will use to implement the Pennsylvania Pilot program are those which have been provided by FERC.

Q. Mr. Coles' testimony at p. 16, line 9 in response to a question concerning planning reserves states "Regional pools such as ECAR have found it economic to have shared reserve responsibility, and use a percentage planning reserve requirement rather than having each utility provide its own reserves" Do you have a comment?

A. Yes. This statement is included in Mr. Coles' response to a question concerning planning reserves, but the statement refers to the current ECAR practice of sharing operating reserves. The ECAR companies do not share planning reserves.

Q. Does this complete your rebuttal testimony?

A. Yes.

R-00974104, R-00974104C0001
C0002

VOLUME IV

Duquesne Statement No. 10

Pgh 12/17/97
C. Halbert

DOCUMENT
FOLDER

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKETED
DEC 23 1997

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
Ralph L. Nelson

RECEIVED
DEC 18 1997
PA PUBLIC UTILITY COMMISSION
PROTHONOTARY'S OFFICE

Contents:

Regarding O&M Costs, Capital Costs and Equivalent
Availability Factors for the Company's Fossil Generating Units

Duquesne Statement No. 10

DIRECT TESTIMONY OF RALPH L. NELSON

I. Qualifications

Q. Please state your name, address and job title.

A. My name is Ralph L. Nelson and my business address is 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230 - 1930. I am employed by Duquesne Light Company ("Duquesne") as Manager of Operations Services in the Fossil Generation Unit.

Q. Please describe your educational background.

A. I hold a Bachelor of Science Degree in Mechanical Engineering from the University of Pittsburgh.

Q. Please describe your work history at Duquesne.

A. I have been employed by Duquesne for 38 years, during which time I have held a variety of positions performing engineering and management functions. I have worked in every generating station operated by Duquesne in positions that encompass plant operations, maintenance, technical services and plant manager. My assignments in the Fossil Generation Unit general office include operations and technical service support functions and general management, and in these assignments I have been responsible for the supervision of and direct involvement in the development of Power Supply Group Operating Plans, Operating and Maintenance (O&M) and Capital budgets (short and long range), cost reduction strategies, Clean Air Act Amendment (CAAA) Compliance Strategies, and the performance of benchmarking analyses.

Q. Please describe your current responsibilities at Duquesne.

A. As Manager, Operations Services, my primary responsibilities are related to Duquesne's interest in the jointly owned fossil stations which are operated by other utilities. I, along with members of my staff closely monitor operations and technical issues at these facilities as well as costs, performance and reliability, with the general purpose of exercising Duquesne's ownership rights as defined in the operating agreements. In addition, I have oversight responsibilities for the development of the Power Supply Group O & M and Capital budgets, CAAA Compliance Strategies, benchmarking analysis and the Power Supply Group Operating Plans.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission in Duquesne's base rate proceeding at Docket No. R-850021.

II. Purpose of Testimony

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to explain the basis for Duquesne's projections of the operating and maintenance costs for the fossil generating stations including those which are wholly owned and operated by Duquesne and those in which Duquesne has ownership interest but are operated by other electric utility companies. I will also explain the basis of Duquesne's projections of capital expenditures for the previously mentioned fossil stations, including those capital expenditures related to environmental compliance projects. Finally, I will discuss the basis for the availability factor projections for these fossil generating stations. All of the above information has been provided to Mr. Mark G. Karl to support the development of the generation cost of service for the years 1999 to 2005 and an estimate of generation revenue net of variable cost beyond 2005.

III. Operating and Maintenance Expense Projections
(Excluding fuel and fuel related expenses)

Q. Please provide a general description of the procedure that was used to estimate non-fuel O&M expenses at Duquesne's fossil generating stations.

A. For 1997, the projected non-fuel O&M expenses were based on the current 1997 budget which was developed in detail to reflect current labor rates, headcount and other known costs including scheduled maintenance outages, all of which are available with reasonable accuracy. The 1998 projections are based on the most recent Operating Plan which was prepared in the fall of 1996 and projects expenses for a three year horizon. The 1999 projections are also based on the Operating Plan but include some adjustments for revisions to the scheduled maintenance outages. The projected expenses for 1999 became the basis for the years 2000 through 2016. Specifically, the 1999 O&M expenses were escalated by applying a general inflation factor, with adjustments for the anticipated decrease in the workforce headcount through the year 2002 and for scheduled maintenance outages. The projected expenses for the years 1997 through 2016 are tabulated by station in Exhibit RLN-1. As indicated in Exhibit RLN-1, when each station (unit) reached the end of book life, projections for O&M expenditures were decreased to zero.

Q. Please indicate the source of the 1997 budgeted O&M expense data used as the basis for these projections.

A. For each of Duquesne's wholly owned fossil stations, the 1997 O&M budget was developed internally under the general direction of the Vice President of the Power Supply Group. For the jointly owned fossil stations, the 1997 budget was based on information provided by the operating companies for Duquesne's share of the O&M expense.

Q. Please compare Duquesne's projections of future O&M expenses to the historical expenses for the fossil generating stations.

A. Exhibit RLN-2 expresses the O&M expenses on a constant 1996 dollar basis, which provides a clearer comparison of the historical and projected expenses. The data shows that on a total basis, expenses for the years 1993, 1994, 1995 and 1996 averaged $59.6 million. During the years 1997 through 2004, expenses are projected to exceed this level in only three years and are projected at well below this level in the remaining five years. Major overhaul outages are scheduled at Duquesne's Cheswick Power Station (which is our largest generating unit) in two of the three exception years. After the year 2004, the total O&M expenses decline sharply as stations (units) reach the end of book life.

Exhibit RLN-3 is a bar graph which displays the historical O&M expenses from 1988 forward as well as the projected expenses for the years 1997 through 2016. As the result of organizational changes and changes in cost allocations as well as some accounting changes that took place prior to 1993, it was impossible to capture the historical costs exactly as tabulated in Exhibits RLN-1 & RLN-2. Nevertheless, the graph represents with reasonable accuracy, savings achieved by Duquesne's cost reduction efforts and the trend of historical as well as projected O&M expenses. During the period 1988 to 1993, expenses were reduced by approximately 15% and from 1993 through 1996, expenses have increased at approximately the same rate as inflation. However, during this period expenses have exceeded the 1988, 1989, 1990 average in only two years. In 1997, expenses are projected to decrease sharply, primarily because of the sale of Duquesne's interest in Ft. Martin No. 1 Unit and thereafter are trending upward at a rate slightly less than inflation. After 1997, expenses will exceed the 88, 89, 90 average in only two years, which are those years in which Cheswick is scheduled for major maintenance outages.

Q. Why do your projections show zero O&M expenses when station (units) reach the end of book life?

A. As detailed in the testimony of Mr. Karl and Mr. Clayton, Duquesne is not projecting life extension of fossil generating stations (units) beyond their normal book life. The market value of these units will be determined in the final market based valuation described in Mr. Clayton's testimony.

Q. Please cite some examples of Duquesne's efforts and strategies that have been implemented in recent years to reduce O&M expenses at the fossil generating stations.

A. Duquesne has implemented a variety of strategies during the past five or six years including staffing reductions, lengthening the interval between major overhaul outages and the sale of generating assets, to name a few. Over the past five or six years, staffing at Duquesne's wholly owned generating and generating support facilities has been reduced by 106 people or approximately 22% of the work force at an annual savings of approximately $4 million per year. There have been similar staff reductions at those fossil generating stations in which Duquesne is a joint owner. These reductions have been achieved through the implementation of various strategies such as process re-engineering, outsourcing certain functions that can be performed more efficiently by outside contractors and by developing a multi-crafted more productive workforce. Another example of a cost reduction strategy which has been implemented is the lengthening of the interval between planned maintenance outages. This has been accomplished by improving the maintenance work scheduling process and by implementing various predictive maintenance techniques. More recently, Duquesne sold its fifty percent interest in the Fort Martin No. 1 Unit which decreased our O&M expenses by approximately five million dollars per year. As the result of these and other cost reduction efforts, and as indicated in the bar graph in Exhibit RLN-3, during the period 1988 through 1993 Duquesne has been able to reduce O&M expense by approximately 15% and since then, we have limited cost increases to the rate of inflation.

Q. In your opinion, are there any substantial opportunities for Duquesne to reduce its Non-fuel O&M costs below these projections?

A. In my opinion, there are no substantial opportunities for reductions in the non-fuel O&M expenses at Duquesne's fossil generating stations. This applies to both the wholly owned and jointly owned stations. Duquesne and the operating companies at the jointly owned fossil stations have been very aggressive over the past five or six years in our efforts to reduce costs in anticipation of pending competition. As stated earlier in my testimony, Duquesne has significantly reduced staffing levels in order to reduce labor costs and present plans call for continued staffing reductions through the year 2002. We will continue our efforts to improve productivity through the implementation of new work systems such as multi - crafting and self directed work teams and we will continue to implement new technologies as they develop, but as the result of inflation, aging of the fleet and boiler degradation due to the long term effects of mitigating nitrogen oxide emissions, there will be continuous upward pressure on O&M costs. Therefore, in my opinion we will not realize substantial O&M cost reductions until the year 2004, and this is reflected in the total O&M cost projections shown in Exhibit RLN-2 in constant 1996 dollars.

Q. Based upon your experience, with respect to fossil generation, do you believe that these projections of O&M expenses are reasonable?

A. Yes, I believe these non-fuel O&M projections are reasonable and conservative. As stated earlier in my testimony, throughout the forecast period the O&M costs are projected to increase at a rate slightly less than inflation and with the exception of two years, they do not exceed the average of 1988, 1989 and 1990. This indicates that cost savings achieved in the early 90's are being maintained and to the extent that cost increases are slightly less than inflation, some minor, additional savings are being achieved. In addition, cost increases are mitigated in the sense that they do not include potential O&M costs resulting from major equipment failures during the forecast period.

IV. Capital Expenditure Projections

Q. Please explain how the projected capital expenditures were determined for the fossil generating stations.

A. Duquesne's capital expenditures for the fossil generating stations were developed on a unit specific basis in detail for the 1997 budget which was then used for the 1997 projections. The 1998 and 1999 projections are based on the most recent Operating Plan which was prepared in the fall of 1996 and projects expenses over a three year horizon. Some adjustments were made to 1998 and 1999 for some anticipated changes in CAAA expenditures. The anticipated changes in CAAA expenditures are based on assumptions which are shown in Exhibit RLN-4. The years 2000 through 2016 were based on 1999 by adjusting for inflation with adjustments for increased capital expenditures in years when major outages are scheduled and decreased levels of expenditures in the years immediately following a major outage. Adjustments were also made for anticipated projects related to compliance with CAAA and Residential Solid Waste (RSW) Regulations. In addition projected capital expenditures for various stations were reduced in consistent increments in each of the four years preceding the year in which a plant reaches the end of its book life and were reduced to zero in the year following end of book life. The projected capital expenditures are tabulated by station, by year in the categories of General Capital, CAAA and RSW in Exhibit RLN-5. These expenses are also shown in constant 1996 dollars for comparison purposes in Exhibit RLN-6.

Q. Please indicate the source of the projected 1997 capital expenditures for the various fossil generating stations.

A. For each of Duquesne's wholly owned fossil stations the 1997 Capital budget was developed internally under the general direction of the Vice President of the Power Supply Group. This budget was prepared in detail on a station specific basis. For the jointly owned fossil stations, the 1997 budget was based on information provided by the operating companies on a station specific basis for Duquesne's share of the station (unit).

Q. Why are capital expenditures needed for plants that are considered by the company to be, in part or in whole, stranded investments?

A. Whether or not a portion of, or all of, the plant investment is stranded is irrelevant in determining the level of expenditures required to operate the plant. The continued operation of a plant requires a certain level of expenditures, some of which are O&M and some of which are capital as determined by the accounting rules established by the Federal Energy Regulatory Commission (FERC). The capital expenditures projected by Duquesne include expenditures necessary for the routine operation of the plants as well as expenditures necessary to comply with the CAAA and the RSW regulations.

Q. Based upon your experience with respect to fossil plant operation, do you believe these projections of capital expenditures are reasonable?

A. Yes, I believe the projected levels of expenditures are reasonable. As shown in Exhibit RLN-6 (which tabulates the historical and the projected capital expenditures on a constant 1996 dollar basis), except for two years during the period 1997 through 2004, the projected levels of expenditures are less than the average of the years 1994 to 1996. Capital expenditures in 1998 and 2004 exceed the average by a significant amount because Cheswick Power Station is scheduled for a major maintenance outage in each of those years. After the year 2004, capital expenditures decline sharply as stations (units) reach the end of book life and their capital expenditures are reduced to zero.

Furthermore, as with O&M expenses, the estimated capital expenditures are mitigated in the sense that they do not include potential capital expenditures that could result as components fail with greater frequency as the plants age, and there are no provisions for extraordinary or one time events.

Q. Does Duquesne's capital expenditure projection include amounts for life extension, i.e., expenditures designed to extend the operating life of facilities beyond their current book life?

A. No. Duquesne's projected capital expenditure projections do not include amounts for life extension. Typically, life extension costs would include replacement of components such as entire economizer sections or entire superheater sections, or turbine/generator rotors. As discussed in the context of O&M expenditures, Duquesne is not projecting life extension of fossil generating facilities.

V. Equivalent Availability Factors

Q. What is the basis for the equivalent availability factors projected by Duquesne for its fossil generating stations.

A. The projected equivalent availability factors (EAF) shown in Exhibit RLN-7 were developed by taking into consideration five year historical forced outage rates and forced derates, seasonal derates where applicable, and the frequency and duration of scheduled maintenance outages which are the major factors in projecting EAF's.

Q. Please compare the projected EAF's to the historical performance of Duquesne's fossil generating stations and to appropriate industry benchmarks.

A. As indicated earlier in my testimony, the projected EAF's for each Duquesne station are shown in Exhibit RLN-7. Also shown in this exhibit are the five year historical and the industry average EAF for units with similar characteristics. The data in the exhibit indicates that the projected average EAF's for all of Duquesne's fossil generating stations, except Elrama and Eastlake 5, exceed their historical and the industry averages. This is true for all of the years in the projection except for those when major maintenance outages are scheduled. In the case of Elrama and Eastlake 5, the projected average EAF exceeds the historical average, but is less than the industry average.

Q. Do you believe Duquesne's fossil Station EAF projections are reasonable?

A. Yes, I believe these EAF projections are reasonable and aggressive. As stated above, at five of the seven stations (units) the projected average EAF exceeds the industry average and all of the stations projected EAFs exceed their historical performance.

In addition, I believe these projections are aggressive because the long term effects of nitrogen oxide emission reduction strategies on boiler components will present a significant challenge to maintain these projected EAFs.

Q. Is there a link between Duquesne's projections for capital additions and EAF for the fossil generating stations.

A. Generally, there is a link, in that in order to maintain station performance in terms of availability (EAF) and reliability, capital spending must be maintained at some minimum levels for routine replacement of worn out components. However, there is no rigorous mathematical relationship linking EAF to capital spending and by implementing new technologies and addressing the root cause of equipment or component failures that result in the largest contribution to forced outages and forced derates, it is possible to improve EAF while reducing capital expenditures.

Q. Is the information included in your direct testimony and related exhibits true and correct to the best of your knowledge, information and belief?

A. Yes, it is.

Q. Does this conclude your direct testimony?

A. Yes.

FOSSIL NON-FUEL O&M EXPENSES
($ x 1000)

STATION		CHESWICK	ELRAMA	BRUNOT IS	PHILLIPS	EASTLAKE	SAMMIS	MANSFIELD	TOTAL
1993	(A)	18,191	16,753	259	117	5,313	4,498	8,912	54,043
1994	(A)	14,125	17,263	310	215	3,977	5,460	15,027	56,377
1995	(A)	16,420	18,652	327	162	5,210	6,260	12,009	59,040
1996	(A)	18,492	21,891	341	178	3,814	3,638	12,817	61,171
4 YEAR AVG	(A)	16,807	18,640	309	168	4,579	4,964	12,191	57,658
1997	(P)	14,651	20,950	425	292	4,845	4,496	12,859	58,518
1998	(P)	27,920	19,593	430	290	6,551	3,986	12,985	71,755
1999	(P)	15,830	22,772	446	300	6,830	5,689	13,194	65,060
2000	(P)	14,932	20,823	457	308	5,403	3,992	14,959	60,874
2001	(P)	16,816	20,263	468	315	5,999	6,326	13,436	63,624
2002	(P)	16,828	20,359	481	324	6,203	4,225	15,057	63,477
2003	(P)	15,618	23,595	493	332	5,893	6,416	12,403	64,750
2004	(P)	28,562	21,511	506	341	6,552	4,461	15,040	76,974
2005	(P)	18,126		520	350	7,904	6,779	13,393	47,072
2006	(P)	16,858		534		6,398	4,713	17,458	45,962
2007	(P)	19,038		549		7,108	7,446	15,527	49,668
2008	(P)	19,420		563		7,299	4,975	17,705	49,962
2009	(P)	18,173		578		6,933	7,555	14,918	48,157
2010	(P)	31,178		593		7,705	5,248	17,673	62,396
2011	(P)	20,801		609		9,303		15,742	46,455
2012	(P)	19,604		625				20,520	40,749
2013	(P)	21,961						18,806	40,767
2014	(P)	22,420						20,813	43,233
2015	(P)							20,688	20,688
2016	(P)							9,313	9,313

FOSSIL UNITS REMOVED FROM GENERATING LINEUP FOLLOWING THE END OF BOOK LIFE.

STATION	END OF BOOK LIFE
ELRAMA	2004
SAMMIS	2010
EASTLAKE	2011
BRUNOT IS	2012
CHESWICK	2014
MANSFIELD 1	2015

(A) - ACTUAL
(P) - PROJECTED

FOSSIL NON-FUEL O&M EXPENSES

(1996 CONSTANT $ x 1000)

STATION		CHESWICK	ELRAMA	BRUNOT IS	PHILLIPS	EASTLAKE	SAMMIS	MANSFIELD	TOTAL
1993	(A)	19,475	17,936	277	125	5,688	4,816	9,541	57,858
1994	(A)	14,797	18,084	325	225	4,166	5,720	15,741	59,058
1995	(A)	16,765	19,044	334	165	5,319	6,391	12,261	60,280
1996	(A)	18,492	21,891	341	178	3,814	3,638	12,817	61,171
4 YEAR AVG	(A)	17,382	19,239	319	173	4,747	5,141	12,590	59,592
1997	(P)	14,308	20,459	415	285	4,731	4,391	12,558	57,146
1998	(P)	26,600	18,667	410	277	6,242	3,798	12,371	68,364
1999	(P)	14,714	21,167	414		6,349	5,287	12,264	60,195
2000	(P)	13,527	18,864	414		4,895	3,616	13,552	54,870
2001	(P)	14,849	17,892	414		5,297	5,586	11,864	55,901
2002	(P)	14,483	17,521	414		5,338	3,636	12,958	54,351
2003	(P)	13,087	19,772	413		4,938	5,377	10,394	53,981
2004	(P)	23,306	17,552	413		5,346	3,640	12,272	62,529
2005	(P)	14,402		413		6,280	5,386	10,641	37,121
2006	(P)	13,042		413		4,950	3,646	13,506	35,557
2007	(P)	14,355		414		5,359	5,615	11,708	37,451
2008	(P)	14,272		414		5,364	3,656	13,012	36,718
2009	(P)	13,017		414		4,966	5,412	10,685	34,494
2010	(P)	21,745		413		5,374	3,660	12,326	43,518
2011	(P)	14,127		413		6,318		10,691	31,548
2012	(P)	12,963		413				13,569	26,946
2013	(P)	14,141						12,109	26,249
2014	(P)	14,056						13,049	27,105
2015	(P)							12,629	12,629
2016	(P)							5,536	5,536

FOSSIL UNITS REMOVED FROM GENERATING LINEUP FOLLOWING THE END OF BOOK LIFE.

STATION	END OF BOOK LIFE
ELRAMA	2004
SAMMIS	2010
EASTLAKE	2011
BRUNOT IS	2012
CHESWICK	2014
MANSFIELD 1	2015

(A) - ACTUAL
(P) - PROJECTED

NON-FUEL O&M EXPENSES
FOSSIL GENERATION

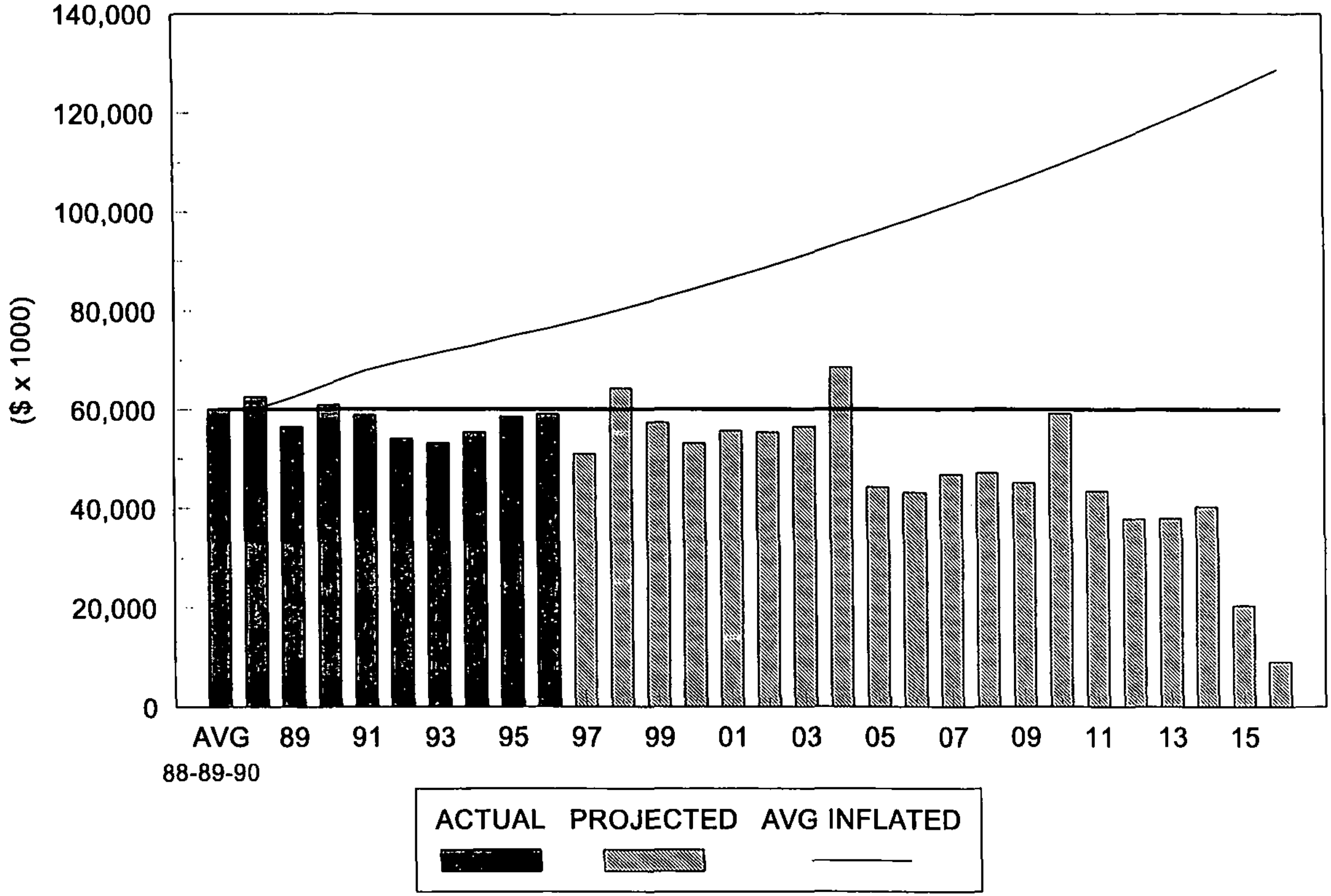

Exhibit RLN-3
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Assumptions Used For Environmental Cost Projections 1997-2017
Air Quality Programs

	Title I - NO_x		Air Toxics	Particulates	Opacity	CO2	Acid Rain SO2
	Current	Likely Scenario	Applies to mercury only.	No additional controls anticipated. EPA shifted away from PM-10 to PM-2.5 which is composed of secondary sulfate and nitrate compounds.		Likely case - no impact.	In 2000, need 40,000 tons additional annual reduction to meet CAP, factor in at $___/ton. Include Eastlake 5 and Sammis 7 (2)
	55% reduction in 1999 (1)	65% in 2005(1)					
Cheswick	Targeted gas burn or coal-water slurry	t.g.b. or c.w.s.	In 2005, most likely scenario is carbon injection, worst case baghouse.		In 2005 ESP upgrade, baghouse or flue gas conditioning		
Elrama	Targeted gas burn or coal-water slurry	t.g.b. or c.w.s.	Determine the size cutoff for each plant and evaluate the suitability to scrubbed plants		N/A		
Phillips	Targeted gas burn or coal-water slurry	t.g.b. or c.w.s.			N/A		
Mansfield	Capacity limit or t.g.b. or c.w.s.	t.g.b. or c.w.s.			N/A		
B.I. Simple cycle Simple cycle with HRSGs Simple cycle with HRSGs and suppl. firing	N/A Water or steam injection w. or s.i.	N/A w. or s.i. w. or s.i.	N/A	Both are addressed by Acid Rain Program SO_2 and Title I NO_x controls	N/A		
Eastlake 5	RACT-2002 LNBs w/OFA	55% in 2005	Evaluate size cutoff		In 2003 - baghouse or ESP upgrade		
Sammis 7	RACT-2002 LNBs w/OFA	55% in 2005			N/A		

Note (1): Requires system analysis of controls necessary at each plant.
Note (2): 40,000 ton annual SO_2 reduction applies on a system basis, including jointly owned plants.

EAU(3):421-97

Exhibit RLN-4
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20-YEAR PROJECTED CAPITAL EXPENDITURES

($ X 1000)

	(A) 1994	(A) 1995	(A) 1996	(A) AVG	(P) 1997	(P) 1998	(P) 1999	(P) 2000	(P) 2001	(P) 2002	(P) 2003	(P) 2004	(P) 2005	(P) 2006	(P) 2007	(P) 2008	(P) 2009	(P) 2010	(P) 2011	(P) 2012	(P) 2013	(P) 2014	(P) 2015	(P) 2016
CHESWICK																								
GEN. CAP	1,329	2,170	3,024	2,174	5,720	11,918	5,758	4,286	4,414	4,547	4,683	14,028	4,969	5,118	5,272	5,431	5,593	14,965	4,451	3,056	1,574	973		
CAAA	344	1,108	1,932	1,128	0	2,210	0	0	0	0	15,125	30,130	0	0	0	0	0	0	0	0	0	0		
RSW	2,074	747	1,586	1,469	2,140	4,640	890	7,610	60	60	60	60	70	70	70	70	80	80	80	80	90	90		
TOTAL	3,747	4,025	6,542	4,771	7,860	18,768	6,648	11,896	4,474	4,607	19,868	44,218	5,039	5,188	5,342	5,501	5,673	15,045	4,531	3,136	1,664	1,063		
ELRAMA																								
GEN. CAP	8,636	4,913	6,807	6,765	10,148	5,172	3,261	3,951	3,052	2,096	1,079	667												
CAAA	5,834	3,653	2,273	3,920	1,363	3,850	150	0	0	0	0	0												
RSW	871	538	11	473	1,505	1,840	2,140	4,250	2,260	270	60	0												
TOTAL	15,341	9,104	9,091	11,179	13,016	10,862	5,551	8,201	5,312	2,366	1,139	667												
BRUNOT IS																								
GEN. CAP	34	41	3	26	888	1,325	1,500	100	103	105	108	111	114	117	120	123	104	107	110	113				
CAAA	0	0	0	0	0	0	0	0	0	0	0	4,200	0	0	0	0	0	0	0	0				
RSW	0	0	0	0	460	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
TOTAL	34	41	3	26	1,348	1,325	1,500	100	103	105	108	4,311	114	117	120	123	104	107	110	113				
PHILLIPS																								
GEN. CAP	0	0	0	0	0	0																		
CAAA	0	0	0	0	0	0																		
RSW	465	156	9	210	401	800																		
TOTAL	465	156	9	210	401	800																		
EASTLAKE																								
GEN. CAP	652	933	32	539	656	1,489	1,234	338	222	778	1,256	3,034	3,469	2,258	526	770	764	905	621					
CAAA	88	96	2	62	1,237	1,637	600	100	5,040	5,100	300	0	0	0	0	0	0	0	0					
RSW	196	38	73	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
TOTAL	936	1,067	107	703	1,893	3,126	1,834	438	5,262	5,878	1,556	3,034	3,469	2,258	526	770	764	905	621					
SAMMIS																								
GEN. CAP	1,582	1,671	819	1,357	1,876	1,134	4,276	472	2,705	5,834	1,697	1,056	1,074	576	3,020	138	432	144						
CAAA	194	46	62	101	38	38	38	0	2,078	100	100	0	0	0	0	0	0	0						
RSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
TOTAL	1,776	1,717	881	1,458	1,914	1,172	4,314	472	4,783	5,934	1,797	1,056	1,074	576	3,020	138	432	144						
MANSFIELD																								
GEN. CAP	9,378	7,774	35	5,729	1,567	2,538	2,318	6,460	2,967	3,289	1,450	3,240	2,430	7,716	3,545	3,927	1,734	3,869	2,902	7,312	3,073	3,703	829	1,06[illegible]
CAAA	3,853	1,144	697	1,898	75	75	75	731	200	350	0	2,900	0	0	0	0	0	0	0	0	0	0	0	[illegible]
RSW	361	101	191	218	547	2,829	460	17	17	50	1,000	2,000	3,000	0	0	0	0	0	0	0	0	0	0	0
TOTAL	13,592	9,019	923	7,845	ERR	ERR	2,853	7,208	3,184	3,689	2,450	8,140	5,430	7,716	0	1,673	2,041	3,278	2,041	4,956	0	2,317	0	460
TOTAL																								
GEN. CAP	21,611	17,502	10,720	16,611	20,855	23,576	18,347	15,607	13,463	16,649	10,273	22,136	12,056	15,785	12,483	10,389	8,627	19,990	8,084	10,481	4,647	4,676	829	1,063
CAAA	10,313	6,047	4,966	7,109	2,713	7,810	863	831	7,318	5,550	15,525	37,230	0	0	0	0	0	0	0	0	0	0	0	0
RSW	3,967	1,580	1,870	2,472	5,053	10,109	3,490	11,877	2,337	380	1,120	2,060	3,070	70	70	70	80	80	80	80	90	90	0	0
TOTAL	35,891	25,129	17,556	26,192	28,621	41,495	22,700	28,315	23,118	22,579	26,918	61,426	15,126	15,855	12,553	10,459	8,707	20,070	8,164	10,561	4,737	4,766	829	1,063

Exhibit RLN-5
Page 1 of 1

20-YEAR PROJECTED CAPITAL EXPENDITURES

(CONSTANT 1996 $ x 1000)

	(A) 1994	(A) 1995	(A) 1996	(A) AVG	(P) 1997	(P) 1998	(P) 1999	(P) 2000	(P) 2001	(P) 2002	(P) 2003	(P) 2004	(P) 2005	(P) 2006	(P) 2007	(P) 2008	(P) 2009	(P) 2010	(P) 2011	(P) 2012	(P) 2013	(P) 2014	(P) 2015	(P) 2016
CHESWICK																								
GEN. CAP	1,392	2,216	3,024	2,211	5,586	11,355	5,352	3,883	3,898	3,913	3,924	11,446	3,948	3,959	3,975	3,991	4,006	10,437	3,023	2,021	1,013	610		
CAAA	360	1,131	1,932	1,141	0	2,106	0	0	0	0	12,675	24,585	0	0	0	0	0	0	0	0	0	0		
RSW	2,173	763	1,586	1,507	2,090	4,421	827	6,894	53	52	50	49	56	54	53	51	57	56	54	53	58	56		
TOTAL	3,925	4,110	6,542	4,859	7,676	17,881	6,179	10,777	3,951	3,965	16,849	36,080	4,004	4,014	4,028	4,043	4,063	10,493	3,077	2,074	1,071	666		
ELRAMA																								
GEN. CAP	9,047	5,016	6,807	6,957	9,910	4,928	3,031	3,579	2,695	1,804	904	544												
CAAA	6,111	3,730	2,273	4,038	1,331	3,668	139	0	0	0	0	0												
RSW	912	549	11	491	1,470	1,753	1,989	3,850	1,996	232	50	0												
TOTAL	16,070	9,295	9,091	11,486	12,711	10,349	5,160	7,430	4,690	2,036	954	544												
BRUNOT IS																								
GEN. CAP	36	42	3	27	867	1,262	1,394	91	91	90	91	91	91	91	90	90	74	75	75	75				
CAAA	0	0	0	0	0	0	0	0	0	0	0	3,427	0	0	0	0	0	0	0	0				
RSW	0	0	0	0	449	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
TOTAL	36	42	3	27	1,316	1,262	1,394	91	91	90	91	3,518	91	91	90	90	74	75	75	75				
PHILLIPS																								
GEN. CAP	0	0	0	0	0	0																		
CAAA	0	0	0	0	0	0																		
RSW	487	159	9	218	392	762																		
TOTAL	487	159	9	218	392	762																		
EASTLAKE																								
GEN. CAP	683	953	32	556	641	1,419	1,147	306	196	670	1,053	2,476	2,756	1,747	397	566	547	631	422					
CAAA	92	98	2	64	1,208	1,560	558	91	4,450	4,389	251	0	0	0	0	0	0	0	0					
RSW	205	39	73	106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
TOTAL	981	1,089	107	726	1,849	2,978	1,705	397	4,646	5,059	1,304	2,476	2,756	1,747	397	566	547	631	422					
SAMMIS																								
GEN. CAP	1,657	1,706	819	1,394	1,832	1,080	3,975	428	2,388	5,021	1,422	862	853	446	2,277	101	309	100						
CAAA	203	47	62	104	37	36	35	0	1,835	86	84	0	0	0	0	0	0	0						
RSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
TOTAL	1,860	1,753	881	1,498	1,869	1,117	4,010	428	4,223	5,107	1,506	862	853	446	2,277	101	309	100						
MANSFIELD																								
GEN. CAP	9,824	7,937	35	5,932	1,530	2,418	2,155	5,852	2,620	2,831	1,215	2,644	1,931	5,969	2,673	2,886	1,242	2,698	1,971	2,021	1,979	2,322	506	632
CAAA	4,036	1,168	697	1,967	73	71	70	662	177	301	0	2,366	0	0	0	0	0	0	0	0	0	0	0	0
RSW	378	103	191	224	534	2,695	428	15	15	43	838	1,632	2,384	0	0	0	0	0	0	53	0	0	0	0
TOTAL	14,238	9,208	923	8,123	0	0	2,652	6,530	2,811	3,175	2,053	6,642	4,314	5,969	0	1,753	2,028	3,347	2,028	4,956	0	2,237	0	449
TOTAL																								
GEN. CAP	22,639	17,870	10,720	17,076	20,366	22,462	17,054	14,139	11,888	14,328	8,609	18,062	9,579	12,212	9,412	7,635	6,179	13,942	5,490	4,116	2,992	2,932	506	632
CAAA	10,803	6,174	4,966	7,314	2,649	7,441	802	753	6,462	4,776	13,010	30,378	0	0	0	0	0	0	0	0	0	0	0	0
RSW	4,156	1,613	1,870	2,546	4,935	9,631	3,244	10,760	2,064	327	939	1,681	2,439	54	53	51	57	56	54	106	58	56	0	0
TOTAL	37,597	25,657	17,556	26,937	27,950	39,534	21,100	25,652	20,413	19,432	22,557	50,121	12,018	12,266	9,465	7,686	6,237	13,998	5,544	4,222	3,050	2,988	506	632

EQUIVALENT AVAILABILITY FACTORS

YEAR	CHESWICK	ELRAMA	SAMMIS #7	EASTLAKE #5	MANSFIELD #1	MANSFIELD #2	MANSFIELD #3
1992	80.95	79.91	92.51	58.98	80.25	91.23	74.53
1993	72.66	74.53	81.23	73.07	86.93	84.09	91.46
1994	88.62	73.58	88.03	65.18	56.47	89.15	87.89
1995	80.41	71.67	74.63	69.73	93.41	62.78	59.14
1996	76.66	74.06	84.66	83.79	74.62	92.99	91.06
92-96 AVG	79.86	74.75	84.21	70.15	78.34	84.05	80.82
0-95 INDUSTRY AV	79.71	85.61	81.75	83.86	85.88	85.88	85.88

1997	87.90	80.30	84.70	78.10	95.60	86.00	88.50
1998	75.90	84.20	95.60	81.20	87.40	95.10	95.60
1999	83.00	82.80	87.40	61.10	94.50	88.80	89.30
2000	90.10	83.50	89.10	91.80	78.10	81.90	94.50
2001	85.80	81.50	78.10	79.70	96.70	92.90	78.10
2002	89.00	87.60	93.40	84.40	90.70	90.40	96.70
2003	84.70	80.30	90.70	78.10	95.60	95.60	90.40
2004	87.90	84.20	95.60	83.30	89.30	89.30	95.60
2005	75.90		87.40	61.10	94.50	94.50	89.30
2006	90.70		89.10	91.20	78.10	81.90	94.50
2007	86.30		78.10	79.20	96.70	92.90	78.10
2008	89.60		93.40	84.40	90.40	90.40	96.70
2009	85.20		90.70	78.10	95.60	95.60	90.40
2010	88.50		95.60	83.30	89.30	89.30	95.60
2011	84.10			61.10	94.50	94.50	89.30
2012	75.90				78.10	81.90	94.50
2013	90.70				96.70	92.90	78.10
2014	86.30				90.40	90.40	96.70
2015					95.60	95.60	90.40
2016						89.30	95.60
PROJECTED AVG.	85.42	83.05	89.21	78.41	90.94	90.46	90.90

R-00974104, R-00974104C0001-C0002

Duquesne Statement No. 10-R

Agu 12/17/97
E. Hubert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Ralph L. Nelson

Contents:

Response to Intervenor Testimony Regarding O&M Costs, Capital Costs, and Potential Cost Reductions for the Company's Fossil Generating Units

REBUTTAL TESTIMONY OF RALPH L. NELSON

Q. Please state your name and business address.

A. Ralph L. Nelson, 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930.

Q. Did you present written direct testimony in this proceeding?

A. Yes. I submitted direct testimony, Duquesne Statement No. 10 in the Duquesne Light Company Restructuring Plan Filing.

Q. What issues will you address in your rebuttal testimony?

A. I will address several issues which witnesses for intervenors Hospital Shared Services Administrative Resources, Inc., City of Pittsburgh, Pennsylvania, and the Office of Consumer Advocate identified in their written direct testimony. Specifically, these issues are:

- The technical issues and unavoidable costs associated with the cold reserving or permanent shut down of Cheswick or Elrama Power Station.
- The required level of NOx reductions assumed in projecting the capital and O&M costs included in my direct testimony for CAAA compliance and the potential impact of CAAA Section 110 SIP call recently proposed by the EPA.
- The potential for non-fuel O&M cost reductions at Duquesne's generating stations, resulting from competitive pressure.

COLD RESERVE CHESWICK OR ELRAMA POWER STATION

Q. Some intervenor witnesses have presented testimony regarding the economic desirability of cold reserving or permanently closing some of Duquesne's fossil generating assets. With regard to the Cheswick and Elrama Power Stations, please describe the technical issues involved in cold-reserving these facilities.

A. There are several issues involved in cold reserving a facility such as Cheswick or Elrama Power Station with the intent to return these plants to service at a later date. The most important aspect involves the preservation of systems and equipment to prevent or minimize degradation during the period of cold reserve. The preservation effort includes engineering studies, analysis of every system in the plant and the development of comprehensive plans for draining and drying systems, establishing flow circuits for the recirculation of dehumidified air through the systems, assuring the weather tightness of the buildings and establishment of plans and schedules for regularly rotating equipment. Caretaker crews must be established to maintain and assure that systems remain dry and to turn rotating equipment on a regular basis. Failure to adequately lay-up these systems and rotate equipment regularly will result in major degradation of systems, equipment and structures which will dramatically increase the cost of reactivating these facilities when they are to be returned to service.

Q. What is the estimated cost of placing a facility such as Cheswick or Elrama in cold reserve?

A. The cost to cold reserve a generating station is very site-specific. Duquesne's only experience with cold reserving a multi-unit station such as Elrama is at Phillips Power Station and based on that experience, the estimated one time cost for laying up the Elrama station is approximately $2,000,000. The annual cost of direct labor and materials for continuous caretaker activities is estimated at $800,000 per year. The estimated one time cost for cold reserving Cheswick Power Station, which is a single unit facility is $1,500,000 and the annual cost of direct labor and materials for continuous caretakers of activities is estimated at $500,000.

Q. What is the estimated cost of reactivating Cheswick or Elrama Power Station after three to five years in cold reserve status?

A. In spite of efforts to preserve the condition of systems, equipment and structures, some degradation will inevitably occur over time. Duquesne has no experience with reactivation of generating units that have been cold reserved for extended periods of time. However, Duquesne's best estimate for reactivating Elrama Power Station after being in cold reserve for three to five years is $51,000,000. Duquesne's estimated cost to reactivate Cheswick after three to five years in cold reserve is $38,000,000. These cost estimates include the estimated cost to rehabilitate degraded equipment and systems, restaff and train employees to operate and maintain the facility, and to provide all of the necessary start-up support functions. The restaffing and training expenses would be necessary because most of the current employees would be either retired or in other positions within the Company.

Q. If Cheswick or Elrama Power Station were to be cold reserved or permanently shut down, would all of the costs associated with these plants be avoided?

A. As I indicated earlier, in the event of a cold reserve situation, there would be lay-up costs and continuous caretaker costs while the plant is in cold reserve. Exclusive of these costs, most of the operating, maintenance and capital costs could be avoided. For example, we would no longer perform overhaul outages and could avoid those costs. Most, if not all O&M costs could be avoided after a short period of time and capital expenditures would be terminated immediately. Also, most future fuel costs could be avoided.

Q. What fuel costs could not be avoided?

A. Elrama's fuel supply includes one contract which does not expire until March 31, 2000. Duquesne is obligated to take 30,000 tons per month and assuming that it could be sold at spot prices, the loss would be limited to approximately $10 per ton. The total take-or-pay unavoidable cost would be approximately $2,000,000. A similar contract that extends for seven years at Cheswick would result in unavoidable costs of $6,700,000.

Q. Are there any other fuel related costs that could not be avoided?

A. Yes, at Elrama Station Duquesne currently contracts for the processing of scrubber sludge for landfill disposal. There would be a one time, first year charge of $1,000,000 for termination of this contract.

Q. With regard to operating costs, could all operation and maintenance (O&M) expenses at Cheswick and Elrama Power Stations be avoided?

A. The variable portion of the O&M expenses would be reduced to zero immediately. I estimate that approximately 50% of the fixed O&M expenses could be eliminated almost immediately after cold reserving or permanently closing the plant. The other 50% would be needed to shut the plant down, lay it up for cold reserve or prepare it for permanent closure. I estimate that these activities would take 12 to 18 months. Thus, the fixed O&M would be reduced by 50% the first year, 75% the second year and 100% thereafter.

Q. What other costs at these stations could be avoided?

A. A portion of the overhead costs would be avoided in varying amounts. The details on these overhead expenses will be addressed in the rebuttal testimony of Mr. Morgan O'Brien. It is estimated that 10% of the allocated overheads would be avoided in the first year of the plant shutdown and 20% in the second year, with the company continuing to incur 80% of the corporate overhead costs thereafter.

Q. Are there any taxes that would be avoided by shutdowns of these stations?

A. Yes, there are. Mr. O'Brien's rebuttal testimony will indicate that with regard to the Pennsylvania capital stock tax, 40% of the capital stock tax allocated to a plant would be avoided once the book value of the plant is written off. In addition, the property taxes would be avoided when the facility is written off. FICA taxes are avoided at the same rate as the workforce reduction.

Q. Are there any other costs that would be incurred as the result of the cold reserving or permanent shut down of Cheswick or Elrama Power Station?

A. If either station were shutdown, the workforce reductions would be achieved largely through layoffs and additional costs would be incurred for employee severance allowances. These costs will also be addressed in the rebuttal testimony of Mr. O'Brien.

Q. Would cold reserving or permanently shutting down either Cheswick or Elrama Power Station create any potential operating problems on Duquesne's transmission system?

A. The Cheswick and Elrama Power Stations are two Duquesne power stations that supply real and reactive power (for voltage support) to customer loads in the eastern portion of Duquesne's transmission system. With Cheswick or Elrama out of service, power flows increase west to east across Duquesne's 138 KV transmission system. The system is designed to handle such increased power flows except that during summer peak load periods or during transmission line outages, which occur infrequently, ampere overloads on transmission lines or low voltage conditions caused by insufficient reactive power supply in certain areas can result in the necessity to interrupt or curtail customers in the affected areas.

Q. Can the transmission system be modified to avoid these problems if Cheswick or Elrama Power Station is shut down?

A. Yes, there are several alternatives for modification to the transmission system that could be implemented to avoid the potential for reliability problems with the shut down of either Cheswick or Elrama Power Station. Mr. Karl will present rebuttal testimony on these alternatives specifically as they regard a shutdown of the Elrama Power Station.

NOx REDUCTION ASSUMPTIONS

Q. What level of NOx reductions was assumed under Title I of the CAAA in the development of the capital and O&M projections in your direct testimony?

A. In my direct testimony, it was assumed that under Title I of the CAAA, plants located in Pennsylvania would be required to reduce their NOx emissions by 65% beginning in the year 2005. Plants located in Ohio would be required to reduce their NOx emissions by 55% beginning in 2005. The capital and O&M expenses necessary to implement the control options to achieve these assumed reduction levels were included in the cost projections. Duquesne is currently implementing the controls to achieve the 55% NOx reduction called for in the existing PA State Implementation Plan.

Q. Since you filed your direct testimony, has there been any events that will impact your assumptions for required NOx reductions?

A. Yes. The EPA recently issued a proposed CAAA Section 110 State Implementation Plan (SIP) call that will increase Duquesne's NOx reduction requirements to 85% as early as 2004. This would apply to plants located in Ohio as well as those in Pennsylvania and will most likely require the installation of Selective Catalytic Reduction (SCR) technology on these units in order to comply.

Q. Will this proposed SIP call significantly increase Duquesne's capital and O&M cost projections for the fossil units?

A. This proposed SIP call will significantly increase these projected expenditures. The estimated capital cost to install SCR technology and the cost to operate these systems is very site specific. However, an average cost for this technology would be $80 per installed kilowatt. The table shown below indicates the estimate capital requirements as well as the estimated annual O&M cost for each of Duquesne's fossil generating plants.

PLANT	CAPITAL $x1000	O&M $x1000
Cheswick	**45,600**	**4,300**
Elrama	**67,200**	**2,900**
Eastlake	**14,880**	**1,048**
Sammis	**14,960**	**1,054**
Mansfield	**30,000**	**1,542**

The data in the table represents the estimated costs to install and operate SCR technology at each plant. At this time, Duquesne has not developed a compliance strategy to comply with the NOx reductions proposed in the EPA's recent SIP call. While it is unlikely that it would be necessary to install SCR's at all of these plants, if these proposed reductions become final, it will be necessary to install this technology at most of these facilities. None of these costs were included in my original or revised testimony.

IMPACT OF COMPETITION ON O&M COSTS

Q. A substantial amount of testimony has been filed by intervenor witnesses regarding the potential for cost reductions at Duquesne's fossil plants. For example, in Mr. Kahal's testimony, he references a U.S. Department of Energy (DOE) study in which it is assumed that the non-fuel operating costs will decline by 25 percent due to the onset of retail competition, with a "high efficiency" scenario assuming a 40 percent decline. In your opinion, are these realistic assessments of the cost reduction potential at Duquesne's fossil generating stations?

A. In my view, the potential to reduce non-fuel O&M costs is specific to individual plants for a number of reasons, including the type of fuel, the specific type and manufacturer of the equipment, and the age of the plant just to mention a few. The statements referenced in the DOE study are general in nature and do not necessarily apply to individual plants. As I indicated in my original testimony, Duquesne has achieved significant reductions in O&M expenses at our fossil generating stations through the early 1990's and in recent years costs have increased at approximately the rate of inflation. As we move forward, costs are projected to increase at a rate slightly less than the rate of inflation, indicating that in terms of constant dollars, some productivity gains are being achieved. Duquesne has and will continue to seek ways to improve technologies and best practices as they develop. However, as the result of the aging of the fleet and anticipated degradation of the boilers due to the long term effects of mitigating nitrogen oxide emissions, there will be continuous upward pressure on O&M costs. In my opinion, these factors will, to a large degree, offset cost reductions achieved through productivity enhancements, thereby limiting the potential for future overall reductions in direct O&M expenses.

Q. Are there any other matters you wish to discusss?

A. Yes. I am sponsoring certain revised exhibits to my direct testimony. These exhibits were circulated to the parties on October 16, 1997 as part of Duquesne's corrections to its stranded cost calculations. For convience, the entire package of revisions is included in Duquesne's rebuttal case as Ex. DJC-21, including my revised exhibits.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

R-00974104, R00974104C 0001-C 0002

VOLUME IV

Duquesne Statement No. 11

Pghe 12/17/97
G Gantz

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCUMENT FOLDER

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

DOCKETED
DEC 23 1997

Direct Testimony
of
Ralph Duckworth, Jr.

RECEIVED

DEC 18 1997
PA PUBLIC UTILITY COMMISSION
PROTHONOTARY'S OFFICE

Contents:

Regarding O & M Costs, Capital Costs and Capacity Factors for the Company's Nuclear Generating Units.

DIRECT TESTIMONY OF RALPH E. DUCKWORTH, JR.

Q. Please state your name and business address for the record.

A. My name is Ralph E. Duckworth, Jr. My address is Duquesne Light Company, P.O. Box 4, Shippingport, PA 15077.

Q. By whom are you employed and in what capacity?

A. I am employed by Duquesne Light Company ("DLC") as Controller, Nuclear. In this position, I am responsible for all financial matters affecting DLC's Nuclear Power Division.

Q. Please provide your educational background and prior work experience.

A. I hold a B. A. in Economics from Carnegie Mellon University, and a Masters in Business Administration from the Katz School of Business at the University of Pittsburgh. Following graduation from the University of Pittsburgh in 1974, I joined Deloitte & Touche, a "big six" public accounting firm, as a staff accountant in the audit group. In 1980, I was promoted to a manager's position in the audit group. In these capacities, I provided financial services to a variety of clients. In 1985, I joined DLC as Manager, Regulatory Reporting, where I was responsible for external and internal financial reporting and corporate taxes. In 1987, I assumed the position of Manager, General Accounting, where my responsibilities included the Payroll, Accounts Payable, Stores Accounting, and General Ledger functions for the entire corporation. From 1990 to the present, I have held the position of Controller, Nuclear. In this capacity, I am responsible for all financial activities of DLC's

Nuclear Power Division, including budgeting, forecasting, cost control and financial reporting. I am a Certified Public Accountant in the Commonwealth of Pennsylvania.

Q. Which nuclear plants are included in DLC's Nuclear Power Division?

A. It includes DLC's 47.5% interest in Beaver Valley Unit 1 and 13.74% interest in Beaver Valley Unit 2, both of which are operated by DLC, and DLC's 13.74% interest in the Perry Nuclear Power Plant, which is operated by Centerior Energy Corporation ("Centerior").

Q. What are your responsibilities with respect to the Perry Plant?

A. I provide oversight of budgeting and other financial matters related to DLC's investment in the Perry Plant.

Q. Have you ever provided testimony in an administrative proceeding?

A. Yes. I provided testimony in Centerior's 1995 rate case before the Public Utility Commission of Ohio, and in DLC's proposed power sale to GPU.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the basis for DLC's projections of the operating and maintenance costs for DLC's nuclear generating stations. I will also explain the derivation of DLC's projections of capital expenditures with respect to those generating stations. Finally, I will discuss and support the projected capacity factors for our nuclear units. This information has been provided to Mr. Mark G. Karl (Statement No. 9) to assist in the determination of future generation revenues, net of variable costs, for DLC's generating stations.

Q. Please provide a general description of the procedure that you used to estimate operating and maintenance (O&M) expenses for DLC's nuclear generating stations.

A. I projected non-fuel O&M expenses on a unit basis expressed in 1996 dollars. These expenses were escalated for future years using a general inflation factor provided by Mr. Karl. O&M projections for Beaver Valley Units 1 and 2 are based on our internal nuclear group forecasts for 1997 and beyond, and have been normalized to levelize the cost impact of refueling outages, which occur on an 18 month cycle. O&M projections for the Perry Plant were provided by Centerior, the operator of the plant, and reflect a similar normalization to levelize costs for refueling outages.

Q. Do your projections assume any productivity gains or other cost reductions?

A. Yes. The Beaver Valley projections for 1997 through 1999 reflect plans to further reduce contractor support and some reduction in utility labor costs due to efficiencies gained through reorganization and improvements in our processes. Significantly higher reductions are expected in 2000 and 2001 as the result of implementing key strategies to improve Beaver Valley's infrastructure and core processes through a plan called "Excellence 2000". These projections also reflect reduced refueling outage costs due to improved planning and scheduling of work during those outages.

Q. How will those reductions be achieved?

A. Beaver Valley is currently making a number of major changes to our work planning and scheduling processes, our project management capability, and maintenance and engineering data bases. These changes, when implemented, will allow us to perform more tasks with less manual effort and intervention, and to perform those tasks more efficiently. This, in turn, will allow us to reduce the number of contractors and utility employees at the site.

Q. When will these changes take place?

A. Many of these efforts are currently underway. While we will see some improvement during the next two to three years, the vast majority of the benefits of these efforts will not be fully realized until 2000 or 2001, once the improvements have been fully implemented.

Q. Will there be any improvements at the Perry Plant?

A. Yes. Perry has made significant improvement in reducing its costs over the last two years. As shown in Exhibit RED-1, Perry achieved a 21% reduction in its costs from 1994 to 1996. Further improvements are expected as a result of Perry's implementing additional process improvements through a program called "Perry Plan For Excellence".

Q. Based upon your experience with respect to nuclear generation, do you believe these projections to be reasonable?

A. Yes, they are aggressive, but reasonable. However, I believe that they are also conservative in that they do not reflect costs for extraordinary outages or major equipment failures.

Q. How do these projections compare to past experience?

A. Actual O&M expenses for all generating stations for the years 1992-1996 are shown in Exhibit RED-1. With respect to most of the stations individually, and on an overall basis, the 1997 projection is less than the average of the prior three years' experience. Further, projections for 1998 through 2000 show additional reductions for the process and structural improvements discussed above. Thereafter, costs are increased for the effects of inflation. Additionally, data for years 1992-1996 are expressed in current year dollars. If they are expressed on a constant dollar basis using the inflation factors supplied by Mr. Karl, it shows a clearer picture as to how conservative our forecasts are. Exhibit RED-2 provides the constant dollar comparison.

Q. How will you achieve the cost reductions indicated by your projections?

A. We are making a variety of process and structural improvements that will create efficiencies, streamline work, tighten controls over costs, and allow us to reduce the number of workers at the plants. Some of the more significant programs underway include the DEMMAND project, which is expected to reduce annual operating costs by more than $13 million when fully implemented, hardware enhancements to our local area network system to improve the speed and reliability of our electronic communications, and the establishment of a work control center to better plan, schedule and control our maintenance activities. These programs and others are expected to eventually result in annual savings of approximately $25 million per year.

Q. Why do you believe these projections are aggressive?

A. As just discussed, these projections represent a significant reduction from past experience. If achieved, O&M expenditures for the year 2001 will represent a 60% reduction in constant dollars from the 1994-1996 three year average, as shown in Exhibit RED-2. Further, projected expenditures for Beaver Valley Units 1 and 2 for 2001 are 36% less than the 1993-1995 three year average for Westinghouse two unit sites on a constant dollar basis (see Exhibit RED-2).

Q. In your opinion, are there any substantial opportunities for DLC to reduce its O&M costs below these projections?

A. I do not believe so. We have been successful in recent years in our efforts to control O&M costs in the face of ongoing inflationary pressures. I believe that the projections developed for 2000 and subsequent years represent aggressive targets which are well below our actual experience in the last three years. As an example of our ability to reduce costs, Beaver Valley Unit 1's 11th refueling outage in 1996 cost \$29.7 million, almost \$20 million less than its 9th refueling outage in 1993 which cost \$49.1 million. Further, refueling outage duration decreased from 83 days in 1993 to 49 days in 1996 and represented the shortest outage in the Unit's history.

Although Beaver Valley Unit 2's 6th refueling outage in 1996 was unusually long at 107 days and cost \$34.2 million, its 5th refueling outage in 1995 was only 45 days long and cost \$26.3 million. This represents a significant improvement over the Unit's 4th refueling outage in 1993 which was 81 days long and cost \$30.5 million. Perry has also made significant improvements in its refueling outages. Its 5th refueling outage in 1996 was 76 days long, down from 190 days during its 4th refueling outage in 1994, and cost \$52.9 million, down from \$93.3 million.

Further reductions in outage cost and outage duration are planned for all three units. Additionally, we have reduced staffing by 130 people at Beaver Valley at an annual savings of approximately \$6.5 million in direct labor costs over the past several years. Contractor levels at Beaver Valley have decreased by 45 over the last 2 years, at an estimated savings of \$ 3 million per year. Staffing levels at Perry have decreased by 134 people over the last 3 years at an estimated annual savings of \$6.7 million. Perry has completed a major improvement program entitled the "Perry Course of Action", which has allowed Perry to reduce its O&M costs by 38% on a constant dollar basis from 1993 to 1997 (budget). (See Exhibit RED-2.) Process improvements and reorganization have enabled the nuclear plants to achieve these levels of improvement. As we implement further structural and process improvements, we expect further cost reductions through the year 2000. However, it would not be reasonable to assume a continuation of this trend after that date.

Q. Why are further reductions not reasonable?

A. Our foremost concern with operating a nuclear plant is safety. It is of the utmost importance to maintain a safe plant. It will be necessary to make further changes and improvements to maintain a high level of safety at the nuclear plants and to comply with Nuclear Regulatory Commission requirements. It is essential to maintain high safety standards, and it will require a significant level of ongoing resources to continue to operate safely. It would be imprudent to project a lower level of expenditures, especially after achieving the reductions projected through the year 2000. Further, there is significant uncertainty regarding future government regulation. For example, the United States Department of Energy ("DOE") is obligated to take possession of spent nuclear fuel beginning in 1998. The DOE has already stated that it will not be able to receive spent fuel until 2010 at the earliest. Failure by the DOE to meet its obligations could force utilities, including DLC, to spend millions of dollars in unforeseen costs to store spent nuclear fuel.

Q. You note that Mr. Karl projects expenses beyond 1997 using an inflation adjustment. Have you reviewed Mr. Karl's expense levels beyond 1997, and do you find them to be reasonable?

A. Yes, I have reviewed Mr. Karl's projections of expenses for the years beyond 1997, using a general inflation factor, and I believe these projections are reasonable, and conservative for the reasons previously discussed.

Q. How was the projected level of capital expenditures for the Beaver Valley units determined?

A. Projections of ongoing capital expenditures for Beaver Valley Units 1 and 2 were developed on a unit specific basis and were escalated for future years using a general inflation factor. Projections of 1997, 1998 and 1999 capital expenditures include an incremental level of expenditures for some of the process and structural improvements discussed previously. Thereafter, the expenditures return to a level amount.

Q. Did you develop a projection of capital expenditures for the Perry plant?

A. Yes. We performed an analysis of projected capital projects provided by Centerior, and have used those data as a baseline for 1997 and later years.

Q. Why do Perry's capital expenditure forecasts fluctuate from year to year?

A. As a boiling water reactor, Perry concentrates much of its capital work around refueling outages. Perry is planning to move to a 24-month cycle in the near future, therefore every other year includes a large increment of capital costs.

Q. Why are capital expenditures needed for plants that are considered by the company to be, in part, stranded investments?

A. The term stranded investment is a financial term, not an operating term. Whether or not a portion of the plant investment is stranded is irrelevant in determining the level of expenditures necessary to operate the plant. The continued operation of a plant requires a certain level of expenditures. Certain of these expenditures are capitalized and others are expensed. It is accounting rules established by the Federal Energy Regulatory Commission (FERC) that determine which of these expenditures are operation and maintenance expense and which are capital expenditures. Capital expenditures necessary for the routine operation of the plant are included in the base level of capital expenditures.

Q. Why are capital expenditures for Beaver Valley Unit 2 projected to increase from prior years?

A. Beaver Valley Unit 2 is a relatively new plant; it was brought on line in 1987. However, as it passes 10 years of commercial operation, it will require increased levels of capital expenditures to maintain it in a safe working condition.

Q. In your experience, are these capital expenditures reasonable in amount?

A. Yes. The projected capital expenditures, exclusive of the incremental expenditures for 1997, 1998 and 1999, are consistent with prior years and are among the lowest levels in the industry. Beaver Valley's average capital expenditures for the period 1994 to 1996 are less than one-half of the average 1996 capital expenditures for two-unit Westinghouse PWR sites. Exhibit RED-3 provides the data, in current dollars, that establish this fact. As with operating and maintenance expense, if a constant dollar comparison is made, there is actually a reduction in capital expenditures of nearly 50% from 1992's levels. This comparison is provided in Exhibit RED-4. On a constant dollar basis, projected capital expenditures for Beaver Valley Units 1 and 2 for the year 2001 are 41% lower than the average 1996 capital expenditures for Westinghouse two-unit PWR sites (see Exhibit RED-4).

Q. Why are Perry's recent capital expenditures greater than the industry average?

A. As previously stated, Perry is completing the Perry Course of Action and the Perry Plan for Excellence. These plans include significant plant improvements, including repairs to the service water and circulating water piping systems. They also include the Perry Activity & Resource Management System, which will design and install hardware and software to streamline the work order system and the work management process. As shown in Exhibit RED-3, once these improvements have been completed, Perry's projected capital expenditures fall well below the 1996 comparative average. When stated in constant dollars in Exhibit RED-4, Perry's average projected capital expenditures in years 2000 and beyond are less than 50% of the 1996 comparative average.

Q. Do you believe that Mr. Karl's projection of future increases in capital investsstment for these stations is reasonable?

A. Yes I do, for the same reasons I expressed with respect to O&M expenses, for recognizing that there is no provision included for extraordinary or one time events which may increase capital requirements for the future.

Q. Have you projected capacity factors for the Company's nuclear units?

A. Yes. As shown in Exhibit RED-5, we expect capacity factors to improve over the next several years due to the improvements I discussed earlier.

Q. Are these projections reasonable?

A. Yes. Although they are very aggressive, these capacity factors are reasonable in light of past experience, industry averages, regulatory requirements, and planned operating improvements.

Q. Is the information included in your direct testimony and related exhibits true and correct to the best of your knowledge, information and belief?

A. Yes it is.

Q. Does this conclude your direct testimony?

A. Yes it does.

Exhibit RED-1

Duquesne Light Company
Nuclear Non-Fuel O&M Costs
(millions of dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	77.9	86.0	163.9	113.2	277.1
1993	(A)	89.2	82.9	172.1	170.1	342.2
1994	(A)	78.7	64.7	143.4	170.2	313.6
1995	(A)	81.3	68.3	149.6	168.1	317.7
1996	(A)	75.7	72.5	148.2	134.2	282.4
3 year avg	(A)	78.6	68.5	147.1	157.5	304.6
3 Year Average - 2 Unit Westinghouse PWR Sites (a)				150.4		
1997	(P)	$74.5	75.1	149.6	116.0	265.6
1998	(P)	$69.2	67.8	137.0	102.3	239.3
1999	(P)	$66.7	63.6	130.3	90.0	220.3
2000	(P)	$58.5	55.0	113.5	92.0	205.5
2001	(P)	$57.8	56.4	114.2	95.6	209.8
2002	(P)	$59.5	57.7	117.2	97.8	215.0
2003	(P)	$61.0	59.1	120.1	100.7	220.8
2004	(P)	$62.5	61.0	123.5	103.2	226.7
2005	(P)	$64.5	62.5	127.0	106.2	233.2
2006	(P)	$66.1	64.0	130.1	108.8	238.9
2007	(P)	$67.6	66.0	133.6	111.9	245.5
2008	(P)	$69.7	67.6	137.3	114.6	251.9
2009	(P)	$71.4	69.2	140.6	117.8	258.4
2010	(P)	$73.1	71.3	144.4	120.7	265.1
2011	(P)	$75.5	73.1	148.6	124.2	272.8
2012	(P)	$77.3	74.9	152.2	127.3	279.5
2013	(P)	$79.2	77.3	156.5	131.0	287.5
2014	(P)	$81.7	79.2	160.9	134.3	295.2
2015	(P)	$75.6	81.1	156.7	138.2	294.9
2016	(P)	N/A	83.7	83.7	141.6	225.3

(A) - actual

(P) - projected

(a) - source: Research Data Institute

Exhibit RED-2

Duquesne Light Company
Nuclear Non-Fuel O&M Costs
(millions of constant dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	85.6	94.5	180.1	124.4	304.5
1993	(A)	95.5	88.8	184.3	182.2	366.5
1994	(A)	82.5	67.8	150.2	178.3	328.5
1995	(A)	83.0	69.8	152.8	171.7	324.5
1996	(A)	75.7	72.5	148.2	134.2	282.4
3 year av	(A)	80.4	70.0	150.4	161.4	311.8
3 Year Average - 2 Unit Westinghouse PWR Site				157.4		
1997	(P)	$72.8	$73.3	146.1	$113.3	259.4
1998	(P)	$65.9	$64.6	130.5	$97.5	228.0
1999	(P)	$62.0	$59.1	121.1	$83.7	204.8
2000	(P)	$53.0	$49.9	102.9	$83.4	186.4
2001	(P)	$51.1	$49.8	100.9	$84.5	185.4
2002	(P)	$51.1	$51.0	102.1	$86.4	188.5
2003	(P)	$51.1	$51.0	102.1	$89.0	191.1
2004	(P)	$51.1	$51.0	102.1	$91.2	193.3
2005	(P)	$51.1	$51.0	102.1	$93.9	196.0
2006	(P)	$51.1	$51.0	102.1	$96.2	198.3
2007	(P)	$51.1	$51.0	102.1	$98.9	201.0
2008	(P)	$51.1	$51.0	102.1	$101.3	203.4
2009	(P)	$51.1	$51.0	102.1	$104.1	206.2
2010	(P)	$51.1	$51.0	102.1	$106.7	208.8
2011	(P)	$51.1	$51.0	102.1	$109.8	211.9
2012	(P)	$51.1	$51.0	102.1	$112.5	214.6
2013	(P)	$51.1	$51.0	102.1	$115.8	217.9
2014	(P)	$51.1	$51.0	102.1	$118.7	220.8
2015	(P)	$46.3	$51.0	97.3	$122.1	219.4
2016	(P)	N/A	$51.0	51.0	$125.2	176.2

(A) - actual

(P) - projected

Index: 1996 = 100.0

Exhibit RED-3

Duquesne Light Company
Nuclear Capital Costs
(millions of dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	18.9	18.9	37.8	35.9	73.7
1993	(A)	19.5	6.0	25.5	41.0	66.5
1994	(A)	8.6	1.9	10.5	41.2	51.7
1995	(A)	11.1	4.2	15.3	24.4	39.7
1996	(A)	9.4	6.9	16.3	30.1	46.4
3 year avg	(A)	9.7	4.3	14.0	31.9	45.9
1996 Average - 2 Unit Westinghouse PWR Sites (a)				30.7		
1996 Average - 1 Unit BWR Sites (a)					21.4	
1997	(P)	$14.4	$10.7	25.1	$35.3	60.4
1998	(P)	$13.5	$14.1	27.6	$8.6	36.2
1999	(P)	$13.2	$11.3	24.5	$25.5	50.0
2000	(P)	$10.0	$10.0	20.0	$5.8	25.8
2001	(P)	$10.3	$10.3	20.6	$10.6	31.2
2002	(P)	$10.5	$10.5	21.0	$6.1	27.1
2003	(P)	$10.8	$10.8	21.6	$11.5	33.1
2004	(P)	$11.1	$11.1	22.2	$6.4	28.6
2005	(P)	$11.4	$11.4	22.8	$12.1	34.9
2006	(P)	$11.7	$11.7	23.4	$6.7	30.1
2007	(P)	$12.0	$12.0	24.0	$12.8	36.8
2008	(P)	$12.3	$12.3	24.6	$7.1	31.7
2009	(P)	$12.6	$12.6	25.2	$13.4	38.6
2010	(P)	$13.0	$13.0	26.0	$7.5	33.5
2011	(P)	$13.3	$13.3	26.6	$14.2	40.8
2012	(P)	$13.7	$13.7	27.4	$7.9	35.3
2013	(P)	$14.1	$14.1	28.2	$15.0	43.2
2014	(P)	$14.4	$14.4	28.8	$8.3	37.1
2015	(P)	$14.8	$14.8	29.6	$15.8	45.4
2016	(P)	N/A	$15.2	15.2	$8.8	24.0

(A) - actual

(P) - projected

(a) Source: Electric Utility Cost Comparison Group

Exhibit RED-4

Duquesne Light Company
Nuclear Capital Costs
(millions of constant dollars)

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Total Beaver Valley	Perry Nuclear Power Plant	Total All Units
1992	(A)	20.8	20.8	41.5	39.5	81.0
1993	(A)	20.9	6.4	27.3	43.9	71.2
1994	(A)	9.0	2.0	11.0	43.2	54.2
1995	(A)	11.3	4.3	15.6	24.9	40.5
1996	(A)	9.4	6.9	16.3	30.1	46.4
3 year avg	(A)	9.9	4.4	14.3	32.7	47.0
1996 Average - 2 Unit Westinghouse PWR sites (a)				30.7		
1996 Average - 1 Unit BWR Sites (a)					21.4	
1997	(P)	$14.1	$10.4	24.5	$34.5	59.0
1998	(P)	$12.9	$13.4	26.3	$8.2	34.5
1999	(P)	$12.3	$10.5	22.8	$23.7	46.5
2000	(P)	$9.1	$9.1	18.1	$5.3	23.4
2001	(P)	$9.1	$9.1	18.2	$9.4	27.6
2002	(P)	$9.1	$9.1	18.2	$5.4	23.6
2003	(P)	$9.1	$9.1	18.2	$10.2	28.4
2004	(P)	$9.1	$9.1	18.2	$5.7	23.9
2005	(P)	$9.1	$9.1	18.2	$10.7	28.9
2006	(P)	$9.1	$9.1	18.2	$5.9	24.1
2007	(P)	$9.1	$9.1	18.2	$11.3	29.5
2008	(P)	$9.1	$9.1	18.2	$6.3	24.5
2009	(P)	$9.1	$9.1	18.2	$11.8	30.0
2010	(P)	$9.1	$9.1	18.2	$6.6	24.8
2011	(P)	$9.1	$9.1	18.2	$12.6	30.8
2012	(P)	$9.1	$9.1	18.2	$7.0	25.2
2013	(P)	$9.1	$9.1	18.2	$13.3	31.5
2014	(P)	$9.1	$9.1	18.2	$7.3	25.5
2015	(P)	$9.1	$9.1	18.2	$14.0	32.2
2016	(P)	N/A	$9.1	9.1	$7.8	16.9

(A) - actual
(P) - projected
(a) Source: Electric Utility Cost Comparison Group
Index: 1996 = 100.0

Capacity Factor

Exhibit RED-5

Duquesne Light Company
Nuclear Capacity Factors

Year		Beaver Valley Unit 1	Beaver Valley Unit 2	Perry Nuclear Power Plant
1992	(A)	88.5%	78.4%	69.0%
1993	(A)	61.4%	72.4%	38.7%
1994	(A)	77.6%	97.8%	44.4%
1995	(A)	76.7%	84.1%	87.8%
1996	(A)	80.0%	66.2%	72.0%
3 year avg	(A)	78.1%	82.7%	68.1%
1997	(P)	84.7%	97.0%	81.5%
1998	(P)	95.4%	86.4%	95.6%
1999	(P)	80.8%	86.4%	85.6%
2000	(P)	82.4%	97.0%	96.4%
2001	(P)	97.0%	86.4%	85.8%
2002	(P)	82.4%	86.4%	96.7%
2003	(P)	82.4%	97.0%	85.8%
2004	(P)	97.0%	86.4%	96.4%
2005	(P)	82.4%	86.4%	85.8%
2006	(P)	82.4%	97.0%	96.7%
2007	(P)	97.0%	86.4%	85.8%
2008	(P)	82.4%	86.4%	96.4%
2009	(P)	82.4%	97.0%	85.8%
2010	(P)	97.0%	86.4%	96.7%
2011	(P)	82.4%	86.4%	85.8%
2012	(P)	82.4%	97.0%	96.4%
2013	(P)	97.0%	86.4%	85.8%
2014	(P)	82.4%	86.4%	96.7%
2015	(P)	81.1%	97.0%	85.8%
2016	(P)	N/A	86.4%	96.4%

(A) - actual

(P) - projected

R00974104, R00974104C0001-C0002

Duquesne Statement No. 11-R

Pgn 12/17/97
G. Grantz

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCUMENT FOLDER

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Ralph Duckworth, Jr.

Contents:

Response to Intervenor Testimony Regarding O&M Costs, Capital Costs and Costs Independent of Operation for the Company's Nuclear Generating Units

REBUTTAL TESTIMONY OF RALPH E. DUCKWORTH JR.

Q. Please state your name and address.

A. My name is Ralph E. Duckworth, Jr. and my address is Duquesne Light Company ("Duquesne"), P.O. Box 4, Shippingport, PA.

Q. What is the purpose of your testimony?

A. I will provide rebuttal testimony to the direct testimony of Mr. David Hughes, Mr. Matthew I. Kahal, Mr. Christopher D. Seiple and others.

REBUTTAL OF MR. HUGHES' TESTIMONY

Q. Please summarize the first portion of your testimony.

A. I address Mr. Hughes' allegations that the fuel and non-fuel O&M expenses, as well as capital expenditures, of operating Perry have been excessive since it was placed in service. I conclude that these claims are either incorrect or fail to recognize that prior ratemaking actions of this Commission have protected ratepayers from increased operational costs. Finally, I explain that the operating and financial experience of Perry has improved significantly in recent years.

Q. Does Mr. Hughes offer any evidence of poor operating experience or high operating costs associated with Beaver Valley Unit 2?

A. No. And as my direct testimony shows, Beaver Valley Unit 2 performs very well when compared to the industry.

Q. Is Mr. Hughes correct in his assertion that Perry has suffered from poor operating performance?

A. Only to the limited extent that Perry's performance included a less than 50% operational availability in 1993 and 1994.

Q. What was the consequence of this performance?

A. The Company absorbed more than $34 million of over budget expenditures, Duquesne's share of over budget expenditures at Perry for the years 1993-1996.

Q. Were these costs deferred for consideration in a future rate proceeding?

A. No. They were expensed immediately.

Q. Who paid for these costs?

A. These costs were borne by the Company's stockholders.

Q. Has Duquesne had a base rate proceeding since 1987 in which any increased costs related to the performance of Perry have been included in base rates?

A. No. Duquesne has not had a base rate proceeding since 1987.

Q. How do the Perry non-fuel O&M costs actually paid by customers, that is, the non-fuel O&M cost projections approved in the 1987 rate docket, compare to actual costs at other similar plants?

A. Perry's non-fuel O&M costs per MWH (three-year averages) as compared to the average industry non-fuel O&M costs for other boiling water reactors are described below. The column labeled *Current Approved Rate* shows the 1987 rate case test year projected O&M expenses actually collected from the ratepayers under current rates.

Year	Perry Actual	Average BWR	Current Approved Rate
1989-1991	$20.79	$21.43	$17.07
1990-1992	$17.23	$21.36	$17.07
1991-1993	$20.49	$22.26	$17.07
1992-1994	$28.73	$21.93	$17.07
1993-1995	$28.70	$19.76	$17.07
1994-1996	$22.29	$18.87	$17.07

(Source: FERC Form 1 data provided by UDI/RDI)

The above table shows that although the actual non-fuel O&M costs at Perry have fluctuated somewhat over the life of the Unit, Duquesne's customers continue to pay a non-fuel O&M rate for Perry well below the industry average for other boiling water reactor plants. The table also shows that for the three year average periods 1990-1992 and 1991-1993, the actual O&M costs at Perry were at or below the industry average.

Q. How do current fuel costs compare to the projected fuel costs approved in Duquesne's 1987 rate case?

A. In Duquesne's 1987 rate case, using a future test year ended March 31, 1988, Duquesne's fuel expenses were projected to be $7,661,604 based on a test year net output of 583,000 MWH. The unit fuel expense was projected to be $13.14/MWH. Unit fuel expenses actually experienced at Perry, expressed in both nominal and in inflation adjusted constant 1987 values are as follows:

Year	Nominal $/MWH	Constant 1987 $/MWH	Rate Case Projection $/MWH
1988	14.54	14.04	13.14
1989	13.26	12.29	13.14
1990	12.63	11.21	13.14
1991	11.31	9.66	13.14
1992	10.33	8.59	13.14
1993	12.00	9.72	13.14
1994	12.28	9.72	13.14
1995	9.71	7.50	13.14
1996	6.90	5.20	13.14

As shown above in nearly every year, fuel costs, on either a nominal or constant basis has trended significantly below the projection made for the 1988 test year in Duquesne's 1987 rate case. Perry has therefore actually experienced fuel costs significantly below rate case projections.

Q. Have Duquesne's ratepayers benefitted from of the declining fuel costs at Perry?

A. Yes. Unlike the non-fuel O&M costs, which have not been reflected in rates (because Duquesne has not had a base rate proceeding in the last 10 years), fuel cost charges are reflected in rates through an annual update of the ECR. The actual unit fuel cost at Perry has declined significantly, an average of about 5.6% per year, since 1988. These savings have been passed directly to ratepayers on an annual basis.

Q. Did or are Duquesne's ratepayers paying for capital additions at Perry since the 1987 rate case?

A. No. Duquesne's rates have never been adjusted to reflect subsequent capital additions at Perry.

Q. Has the Commission previously addressed increased costs as a result of the 1993 and 1994 outages at Perry?

A. Yes. The Commission disallowed the recovery of a portion of Perry replacement power costs incurred by Duquesne during 1993 and 1994. As a result of this disallowance, Duquesne's customers have benefitted from the decreases in fuel costs at Perry, without paying the increased Perry purchased power cost incurred by Duquesne as a result of the 1993 and 1994 outages.

Q. Please explain the adjustments made by Duquesne to its ECR with respect to the periods of time when Perry was not in service.

A. An adjustment was made to the ECR in effect for the period April 1, 1994 through March 31, 1995 to reflect the performance of Perry during the 12 month period ended December 31, 1993. The ECR for this period was adjusted downward by $777,409 to reflect the incremental cost of replacement power associated with performance of Perry below a 50% net capacity factor (NCF) as required by Section 1322 of the Public Utility Code. (See In re Duquesne Light Company, Dkt. No. M-940524 (April 8, 1994).)

An adjustment was made in the ECR in effect for the period April 1, 1995 through March 31, 1996 to reflect estimated replacement power costs for the last 70 days of Perry's 4th refueling outage, which lasted from February 5, 1994 through August 13, 1994, a total of 190 days. The ECR for this period was adjusted downward by $2,403,790 to reflect the estimated replacement power costs associated with the 70 days of the Perry 1 refueling outage that extended beyond the 120 day threshold of Section 1322. (See In re Duquesne Light Company, Dkt. No. M-950662 (March 30, 1995).)

Q. Were these adjustments approved by the Commission?

A. Yes. Each adjustment was approved by the Commission as referenced above.

Q. What has been the recent operating availability of the Perry Plant?

A. Greatly improved. Operating availability at nuclear facilities is most appropriately evaluated from a long term perspective, rather than on the basis of only one or two years, because operating availability can vary significantly from year to year as the result of refueling outages and forced outages. Perry's lifetime capacity factor through June 30, 1997 is 61.8%. Perry's capacity factors were 87.5%, 71.3% and 88.7% for 1995, 1996, and the first 8 months of 1997, respectively. Perry's capacity factor for the three year period ended December 31, 1996 was 67.2%, which is not far from the industry average of 74.3%.

Further, Perry recently completed its 6th refueling outage in 41 days, the shortest refueling outage in the Unit's history. This represents a 46% improvement over Perry's 5th refueling outage, which lasted 76 days.

Operating availability at Perry averaged 68.0% over the period 1988 through 1995, with 93.3% availability in 1995 surpassing the previous high of 90.8% in 1991. Averaged over the life of the facility, Perry's operating availability compares favorably with the 64% operating availability target referenced in Mr. Hughes' testimony. During the June through August summer peak period, when Duquesne's need for capacity is at the greatest, Perry's historic operating availability has averaged 82.4%.

In addition, the Nuclear Regulatory Commission has also recognized the improvements in Perry's operating performance and the prospect for continued improvement under current management. (See Systematic Appraisal of Licensee Performance ("SALP") 13 Report for the Perry Nuclear Power Plant (Report No. 50-440/94001); Letter of John B. Martin to Mr. Donald C. Shelton dated February 14, 1995.)

Q. What about Perry's O&M costs?

A. Again, there has been dramatic improvement. Perry's cost per MWH (18 month periods) decreased from $49.66 as of December 31, 1994 to $23.43 as of June 30, 1997, a 53% improvement. Perry's non-fuel O&M costs decreased from $170 million in 1994 to $134 million in 1996, a 21% drop, and are expected to decline to $121 million in 1997.

Q. What are these improvements attributable to?

A. Perry has spent considerable sums of money over the past few years to improve its infrastructure and operating systems. It has made numerous management changes and taken other steps to improve its performance and lower its costs. These actions, including the "Perry Course of Action" and "Perry Plan for Excellence," appear to be having positive results.

Q. Have rates been increased to pay for these extra costs?

A. No, as previously discussed, the capital costs were expensed and ratepayers have been protected from adverse energy cost impacts and, indeed, receive the benefits of positive impacts on energy costs.

Q. Why did Duquesne intervene in Cleveland Electric Illuminating Company's 1995 rate case?

A. CEI is the operator of the Perry Plant. We were concerned over the operating experience at Perry in 1993 and 1994. We believe that our actions had the effect of continuing pressure on Cleveland Electric to reduce Perry's operating costs and improve its performance.

Q. What are the future cost and operating projections for the Perry Plant?

A. The operator of the Perry Station has projected achieving the following key performance goals by the year 2000: 1) reduction in total direct annual O&M expenditures from $168 million in 1995 to $101 million; 2) non-fuel O&M costs will be reduced from 1.84 cents per KWH to 1.00 cent per KWH; 3) the plant availability factor will be increased from the 1995 level of 94.2% to 97.8%; 4) the plant capacity factor will be increased from 86.9% to 95.3%; 5) the forced outage rate will be reduced from 21 days per year to 8 days per year; 5) the plant refueling cycle will be increased from an 18 month to a 24 month cycle; and 6) refueling outage duration will be reduced from 76 days to 40 days.

Q. Is the Perry Plant used and useful in providing utility service to the public?

A. Yes. The Perry plant has clearly been used and useful since the initiation of commercial operation in 1987 and will continue to be used and useful in the future. Specifically, the Perry Plant has been used and useful for the following reasons:

1.) Perry has provided capacity in meeting the needs of retail customers.

The Perry Power Plant has provided 161 MW of summer rated capacity and 164 MW of winter rated capacity since the facility achieved commercial operation status in November, 1987. Perry currently represents 5.8% of Duquesne's active summer and winter capacity line-up. Perry was on-line meeting customer capacity needs during the Duquesne all-time system peak of 2,666 MW established during the summer of 1995, and Perry was an important generating asset during the capacity shortage in the power supply crisis of January 1995. Since the facility achieved commercial operation status in November 1987, Perry has been on-line meeting customer capacity needs more than 80% of the hours during Duquesne's critical annual summer peak period of June through August.

2.) Perry has provided energy in meeting the needs of Duquesne's retail customers.

The Perry Power Plant, while providing 5.8% of Duquesne's active capacity, has provided, over the life of the facility, an average of 909,901 MWH of energy output annually, representing an average of 7.2% of the total annual energy needs of Duquesne's retail customers. In 1995 Perry provided 1,255,429 MWH of energy output, 9.5% of the total energy needs of retail customers. In 1994, despite an extended refueling outage, Perry met 4.9% of the total energy needs of retail customers. In 1993, despite a series of forced outages, Perry met 4.3% of the total energy needs of retail customers.

3.) The lifetime operating availability of Perry Unit 1 compares favorably with the 1987 rate case projections and with industry averages.

Operating availability at Perry averaged 68.0% over the period 1988 through 1995, with 93.3% availability in 1995 surpassing the previous high of 90.8% in 1991. Averaged over the life of the facility, Perry's operating availability compares favorably with the 64% operating availability target referenced in Mr.

Hughes' testimony. During the June through August summer peak period, when Duquesne's need for capacity is at the greatest, Perry's historic operating availability has averaged 82.4%.

UNAVOIDED NUCLEAR PLANT COSTS UNDER AN EARLY SHUT DOWN SCENARIO

Q. What is the purpose of this portion of your testimony?

A. I will provide rebuttal testimony to certain portions of the direct testimony of Matthew I. Kahal, representing the Office of Consumer Advocate, Christopher D. Seiple, representing the City Of Pittsburgh, and others. Specifically, I will rebut their contention that all of the site-related costs associated with the Perry Nuclear Power Plant could all be avoided if the unit were shut down prematurely. I will address fuel costs, O&M costs, capital expenditures, and decommissioning costs. Mr. O'Brien will address in his rebuttal testimony whether certain corporate costs can be avoided if the unit were closed early.

Q. These interveners in their direct testimony have advocated the early closure of certain of Duquesne's's generating units, including Perry. What is Duquesne's ownership interest in the Perry Plant?

A. Duquesne owns 13.74% of Perry.

Q. Who owns the rest of the unit?

A. Ohio Edison owns 30%, Cleveland Electric Illuminating has a 31.11% interest, Toledo Edison has a 19.91% interest, and Pennsylvania Power owns 5.24% of the plant.

Q. Are these companies known as the CAPCO companies?

A. Yes.

Q. Do the CAPCO companies jointly own any other generating units?

A. Yes. There are several jointly-owned units.

Q. Who operates Perry?

A. Cleveland Electric Illuminating (CEI) operates the Perry Plant on behalf of the other CAPCO companies.

Q. As operator of the plant, does CEI have sole discretion in making all decisions regarding the plant?

A. No. CEI makes decisions regarding the day to day operations of the plant; however, major decisions regarding the plant require the unanimous agreement of CAPCO.

Q. Could CEI unilaterally close Perry?

A. No. CEI could not take this action on its own. It would be required to obtain the agreement of the other CAPCO companies before shutting the plant down.

Q. Could Duquesne unilaterally close Perry?

A. No, for the same reason.

Q. Are there any contracts that govern the operations and decisions regarding Perry?

A. Yes. There is the Basic CAPCO Agreement, which governs the overall CAPCO arrangements. There also is a specific Perry Operating Agreement.

Q. Do these contracts specify that unanimous agreement among the CAPCO companies is required to prematurely close a plant?

A. Yes.

Q. Do these contracts contain any language regarding the sharing of operating and capital costs among the owners?

A. Yes. They specify that the non-operator owners, such as Duquesne in the case of Perry, must reimburse the operator owner for their pro rata shares of the operating and capital costs associated with the unit.

Q. Could Duquesne simply stop paying its share of the operating and capital costs associated with Perry?

A. No. Duquesne is contractually bound to the terms and conditions of the agreements governing the operation of the units. Duquesne is obligated to continue to pay its share of Perry's costs.

Q. Have the other owners of Perry indicated their willingness or desire to close the unit?

A. No.

Q. If the CAPCO companies were to agree to close Perry, would all of the associated costs be avoided immediately?

A. No. Certainly some of the costs could be avoided. For example, we would no longer perform refueling outages and could avoid those costs. We would also terminate any further capital expenditures for the unit. Most future fuel costs also could be avoided.

Q. What fuel related costs could not be avoided?

A. At the time of shutdown there would be a certain amount of nuclear fuel that would not have been consumed during operations. This is because most fuel is consumed over the course of two or three operating cycles. The cost of the fuel is expensed over the same period of time. Thus at any given time there is a balance of fuel costs not yet expensed. These costs would have to be written off at the time the plant was closed.

Q. What would those costs amount to?

A. That would depend on where in the fuel cycle we were when the unit was shut down. As an indication, Duquesne's share of unexpensed fuel at Perry at the end of 1997 is projected to be $13.5 million.

Q. *Could you sell the unused fuel to another utility?*

A. No. The unused fuel resides in structures called fuel assemblies. The fuel inside each assembly would be partially consumed. Further, the assemblies are highly radioactive and could not be readily transported to another plant. Therefore, the fuel would not be of any use to another utility.

Q. Are there any other fuel related costs that could not be avoided?

A. Yes. We have fuel in the process of being fabricated. We would need to cancel the contracts for those services. We would also still be liable to the United States Department of Energy for the so-called uranium enrichment facilities decontamination and decommissioning surcharges.

Q. What would be the amount of these costs?

A. Again it would depend on when we cancelled the contract and just how much fuel was under contract for fabrication. As an example, it would cost Duquesne $4.7 million to cancel the Perry fabrication contracts as of the end of 1997. The liability for the decontamination and decommissioning charges is $1.2 million for Perry.

Q. You mentioned earlier that some operating costs could be avoided. Could all operations and maintenance expenses be avoided?

A. No, not immediately. I estimate that approximately 50% of O&M expenses could be eliminated shortly after plant closure. The other 50% would be needed to safely shut the plant down, obtain required regulatory approvals, and prepare the plant for decommissioning. I estimate that these activities would take at least a year to complete. Thus I would expect that half of the unit's current operating expenses would continue for at least one year after plant shutdown. Thereafter site activities would be associated with decommissioning the unit.

Q. Are there any new, incremental costs that would be incurred if a unit were shut down?

A. Yes. We would incur severance costs for those employees at the unit who would be laid off. I have estimated Duquesne's share of those costs to be $3.6 million at Perry in each of the first two years following shutdown.

Q. Are there any other incremental costs that would be incurred?

A. Yes. We would be required to write off the balance of the spare parts inventory at the plant. Based on current inventory levels, this would amount to $4.0 million for Duquesne.

Q. Couldn't this inventory be sold to other plants?

A. No. My experience shows that there is no market for excess nuclear inventory. Most plants are conducting programs to reduce inventory levels. However, I have assumed a 5% scrap value for the inventory.

Q. Would the basic requirements and actions needed to decommission a unit change significantly if it were closed prematurely?

A. Yes. Such costs would increase.

Q. Why would decommissioning costs increase?

A. There are two reasons. First, decommissioning costs would be paid sooner than if the unit operated until the end of its expected life.

Q. Why would this make a difference?

A. The funds in the decommissioning trusts would not have had an opportunity to accumulate and earn a net return from fund investments.

Q. Aren't decommissioning costs expected to escalate over time?

A. Yes; however, trust earnings are expected to increase at a higher rate. This means that in real terms it would be more expensive to close a plant early and decommission it as compared to decommissioning the plant at the end of its operating life.

Q. You mentioned there were two reasons that these costs would increase. What is the second reason?

A. The unit's spent fuel would need to be removed from the reactor and stored in dry casks to permit the unit to be decommissioned. The fuel would be maintained on site in the casks until the Department of Energy (DOE) accepted shipment of the spent fuel. Various systems, such as security and radiological monitoring, would need to be maintained to ensure that the fuel was being stored safely. It is estimated that there would be an initial capital cost of $20 million ($2.7 million Duquesne share) to construct the storage facilities, and that it would cost $.4 million per year (in current dollars) to maintain the spent fuel storage facilities.

Q. Wouldn't the spent fuel have to be maintained on site even if the unit operated until the expiration of its operating license?

A. Yes. However, much of the fuel could be stored in the existing spent fuel pool if the unit were allowed to operate until expiration of the operating license. If the unit is closed and decommissioned prematurely, dry cask storage will begin much earlier and be required for a longer period of time.

Q. What would be the difference in time dry cask storage would be required?

A. Using the current DOE schedule for accepting fuel, dry cask storage capability would be required for 34 years if a unit closes prematurely, as opposed to 15 years if the unit operated to the end of its license.

Q. What would this mean in terms of cost?

A. This means that early shut down of a unit would add 19 years of dry cask storage costs at $.4 million per year.

Q. Please summarize this portion of your testimony.

A. Early shutdown of a unit does not eliminate all of its associated costs, and in fact adds certain new costs. It is simplistic and inaccurate for the intervenors to argue that a unit's costs can all be avoided if it is shut down prematurely.

REBUTTAL OF MR. KAHAL'S TESTIMONY

Q. Mr. Kahal contends that Perry and Beaver Valley 2 are uneconomic and should be shut down. He believes that allowing those plants to operate would cause "ratepayers to subsidize operating losses on these plants during the transition period." He claims that "Duquesne could save more than $200 million in net operating expenses, after accounting for the added cost of purchasing replacement power." Do you agree with Mr. Kahal's contentions?

A. No. As Mr. Clayton shows in his rebuttal testimony, there are no savings from closing these plants early. Mr. Kahal offers no support for his calculation of the $200 million in purported savings. As I have shown above, there are numerous costs that cannot be avoided in the event of an early plant shut down.

Q. Mr. Kahal also believes that future plant O&M costs should be reduced to reflect assumed productivity gains, and proposes a 10% reduction in those costs. Do you agree with Mr. Kahal's view?

A. No. Future productivity gains for the nuclear plants have already been reflected in projected O&M and capital costs. Costs were fixed beginning in 2002 because it is not responsible to assume further gains that far out into the future. Significant improvements in plant costs have already been achieved in recent years. There are too many uncertainties associated with future regulatory requirements, equipment degradation, technology issues, price inflation and other factors that can influence future costs. These uncertainties would tend to offset any additional productivity gains. It would be speculative and irresponsible to project productivity gains beyond what Duquesne has already reflected in its calculations. Mr. Kahal has provided no specific evidence to support his position that future productivity gains are necessary. His proposal to infer a 10% productivity gain is arbitrary and the Commission should not accept Mr. Kahal's adjustments.

NUCLEAR DECOMMISSIONING COSTS

Q. Mr. Catlin suggests that the contingency in the nuclear decommissioning calculations should be lowered to 10%. Do you agree with this proposal?

A. No. Mr. Catlin provides no evidence to support the adequacy of a lowered contingency. In fact, Environmentalists witness Biewald correctly notes that the Company's nuclear decommissioning cost obligation is "large, very uncertain" and that decommissioning expense estimates have "out paced inflation by about 10% per year." He goes on to state that, "Dismantling large, highly radioactive nuclear units is a large, complex undertaking for which experience is currently quite limited, and regulations continue to evolve....Any current estimate of nuclear decommissioning costs is subject to considerable uncertainty – technical, economic, and regulatory." These arguments support the need for a significant contingency factor in the decommissioning cost estimates. The Commission should reject Mr. Catlin's argument for a lower contingency factor.

Q. Do you wish to rebut any of Mr. Biewald's direct testimony concerning nuclear decommissioning costs?

A. Yes. Mr. Biewald asserts that the Company's decommissioning liability is to some extent within the control of the plant owner, and that the Company has not adequately taken steps to mitigate decommissioning costs. Decommissioning costs are largely attributable to the design of the plant, meaning how much concrete, piping, and other materials were used to construct the unit. Decommissioning costs are also driven by the cost to dispose of low level radioactive waste and the labor costs to conduct the decommissioning activities. None of these costs are determined by how a unit is operated. Nor are they determined by how long the unit is operated. Thus Mr. Biewald is incorrect in his assertions that decommissioning costs are determined by how a plant is operated.

I would also point out that the Company has attempted to mitigate decommissioning costs by seeking to invest decommissioning funds in investments that will maximize trust fund earnings and therefore minimize the costs to the ratepayers. Also, the Company plans a strategy of timing the decommissioning of the Beaver Valley units so as to achieve the economies of scale of decommissioning two units at the same time, rather than separately. Again, this minimizes the costs to ratepayers. Finally, the Company unilaterally increased its contributions to the decommissioning trust funds. This action funds the trusts more rapidly and allows the trusts to grow faster as the result of returns earned on the fund investments. Again, Mr. Biewald errs in his conclusions.

Finally, Mr. Biewald comments that decommissioning costs should be the responsibility of the Company because it has not operated the units as "cleanly" as possible. He proposes that such costs be treated as operating costs. This is a ridiculous statement. I would be very interested in knowing how Mr. Biewald would operate a nuclear plant without contaminating major portions of the plant. As I stated above, once a plant has begun operations, the effort to decommission the unit has been determined. Total costs are therefore after determined by the rate of inflation, labor costs and waste disposal costs. These are factors that are beyond the Company's control and are independent of the continued operation of the plant.

Q. Are there any other matters you wish to discusss?

A. Yes. I am sponsoring certain revised exhibits to my direct testimony. These exhibits were circulated to the parties on October 16, 1997 as part of Duquesne's corrections to its stranded cost calculations. For convience, the entire package of revisions is included in Duquesne's rebuttal case as Ex. DJC-21, including my revised exhibits.

Q. Does this conclude your testimony?

A. Yes.

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VOLUME IV

Duquesne Statement No. 12

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

DOCUMENT FOLDER

DOCKETED DEC 23 1997

Direct Testimony
of
Jeff D. Makholm, Ph.D.

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PA PUBLIC UTILITY COMMISSION PROTHONOTARY'S OFFICE

Contents:

Regarding Rate of Return On Equity.

DUQUESNE STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF DUQUESNE LIGHT COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

JEFF D. MAKHOLM, Ph.D.

Regarding cost of capital and other issues related to shareholders' historical levels of compensation and current market to book values for the common stock of Duquesne Light Company

n/e/r/a
Consulting Economists

I. INTRODUCTION

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. (NERA). NERA is a firm of consulting economists with its principal offices in a number of major U.S. and European cities. My business address is One Main Street, Cambridge, Massachusetts, 02142.

Q. Please describe your academic background.

A. I have M.A. and Ph.D. degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University, in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience.

A. My work centers on economic issues involving pricing, regulation and market issues for the natural gas and electricity industries, among others. My consulting work includes the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. I have prepared expert testimony and statements, and have appeared as an expert witness in many state, federal and United States District Court proceedings, as well as in regulatory hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries abroad. In these countries, I have drafted regulations, established tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work pertaining to the gas industry, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Regarding rate of return and utility financing questions specifically, I have testified for electric, natural gas, water and telecommunications utility clients before state commissions in Pennsylvania, Oregon, North Carolina, Kansas, New Jersey, New York, Maryland, California, Virginia, Rhode Island and Wisconsin, as well as the Federal Energy Regulatory Commission (FERC). My current vita, detailing more fully my educational and consulting experience, is attached to this testimony.

Q. Does your testimony in this proceeding determine the fair rate of return on equity on behalf of Duquesne Light Company ("Duquesne")?

A. Yes. This return on equity will be used by the Company to calculate its revenue requirement and to discount its first stage estimate of market value and stranded costs.

Q. Please summarize your conclusion as to the fair rate of return on equity for Duquesne.

A. The fair rate of return I recommend for Duquesne is **11.65 percent**, which I conclude is reasonable for the Company. This recommendation is based on a Discounted Cash Flow (DCF) analysis of 17 comparable electric utilities.

Q. How would you characterize the nature of your rate-of-return evidence?

A. One of the most important goals in my rate-of-return evidence is to minimize the amount of subjectivity in the process of determining the fair rate of return. I view subjectivity as the principal source of contention in calculating the rate of return in utilities' rate cases. This subjectivity has four sources: (1) lack of attention to detail in employing the methods provided by decades of work in the field of theoretical finance; (2) a proliferation of quantitative approaches to determining the cost of capital, under the dubious premise that the use of *more methods*—no matter how shaky the foundation for each—provides better rate-of-return evidence; (3) insufficient candor on the part of analysts regarding when they have applied objective, reproducible standards in their analysis and when they have resorted to personal judgment; and finally, (4) subjective adjustments to the results of empirical analyses.

These four sources of subjectivity create a regulatory atmosphere in which it is very difficult, if not impossible, to resolve the contentious issues surrounding the setting of the fair rate of return. Most, if not all, other issues in rate cases have objective standards (*e.g.*, legal, policy, empirical) upon which to measure the value of evidence presented in rate cases. Only the process of finding the fair rate of return seems immune to measurement by such standards.[1]

To avoid this contention, I make every attempt to avoid injecting subjectivity into calculating the fair rate of return. That is, I am very careful in the models I use and the type of data I apply to those models. I also resist performing a multitude of ROE calculations, because I conclude that approach generally obscures rather than clarifies. I make clear where the use of judgment is unavoidable, and I explain the basis for that judgment. Finally, I strictly avoid making subjective "risk" adjustments to the fair return that do not have a solid and empirically verifiable financial basis. Rate-of-return analysis suffers widely from a fog of *ad hoc* adjustments to calculated results that are impossible to verify empirically or theoretically.

As a result, the standards to which I hold my evidence, as well as that of others, are (1) clarity; (2) theoretical support; (3) empirical objectivity; (4) stability (*i.e.*, not producing widely disparate results); and (5) the ability to reproduce (*i.e.*, allowing others to relatively easily recompute my results). My evidence for Duquesne reflects my desire to hold to these five standards of evidence.

Q. Do you engage in detailed discussions of general economic trends?

A. No. I do not include much of the discussion of general economic trends, Central Bank policy, etc., that the Commission may have seen in the past. Such discussions, although interesting because they point out recent trends in capital markets, do not inform us regarding what *investors* believe is going to happen in the future. In order to gauge investor expectations, we must resort to the financial models that have become familiar in rate-of-return proceedings. These models all employ the markets for utility securities as the source of investors' verdicts regarding the cost of capital.

The markets for utility securities provide the best (and indeed the only) evidence on what investors require as a return on the money they invest in utilities, and the financial models that currently exist put evidence from that market in its proper context. The utility security markets

[1] Attached as **Exhibit JDM - 1** is my article "Rate of Return in a More Progressive Regulatory Rate-Setting Process, or Can We Untie the Gordian Knot?," *NERA Topics*, March 1994, where I discussed the problems associated with rate-of-return investigations. This article is based on a 1993 speech I gave to the National Society of Rate of Return Analysts at their annual forum in Philadelphia.

use general economic information in the most efficient way. It is neither efficient nor appropriate for us to render a verdict on where *we* think markets are headed when the law requires us to try to reflect what *investors* think. Our task should be to take *investors'* verdicts on the value of utility securities, combined with sound financial models, to determine the fair rate of return in the most direct and objective way possible.

Q. How does your evidence in this case reflect your desire to pursue objective, reliable and reproducible results?

A. I pursue these goals in two main ways: (1) by using those financial models and methods that permit the greatest objectivity; and (2) by making use of comparable company groups (also known as "proxy groups") to draw more reliable conclusions about investors' expectations.

Q. Please discuss how the selection of financial models and methods facilitates the greatest objectivity in finding the fair rate of return.

A. Although much time is devoted to discussions of various techniques for finding the fair rate of return, little discussion is usually devoted to determining whether these techniques are practical in the rate case setting and whether they are capable of limiting the scope for contention in rate cases. There are two main attributes of financial models that help on both counts: (1) the models should be strictly forward-looking; and (2) the models should be able to offer an objective way of dealing with the uncertainty that is inherent in gauging investors' future expectations.

Q. Why is a forward-looking perspective important?

A. Investors are thinking about the future when they demand compensation for the use of their money. Therefore, the cost of capital is a forward-looking concept. However, there are few ways of looking into the future, particularly from the perspective of what *investors* expect to occur. Those ways are generally indirect—we look at stock prices or interest rates to gauge these expectations indirectly. This is precisely why the field of finance has developed models like the DCF and Capital Asset Pricing Model (CAPM). Those models are designed to take the limited types of information we *can observe* to draw conclusions about *unobservable* investor expectations of the future.

A forward focus and the use of valid financial models reduces the type of information that can help determine the cost of capital. There is only a limited amount of information, either observed (such as stock prices and interest rates) or produced by disinterested sources (forecasts from widely distributed financial advisory services), that fits our needs in the context of the available financial models. The use of this information helps in rate cases by limiting the source of contention, minimizing the role of subjective judgment, and restricting the ability to bias the results.

By contrast, if we abandon a strict forward focus we open the floodgates to a sea of information that: (1) has no valid use in determining today's investors' expectations; and (2) can be used selectively to bias rate-of-return results. With *any* backward-looking method of determining the rate of return, we can greatly alter the results simply by changing the historical time period used (*e.g.*, two years, five years, fifty years). Furthermore, we abandon financial theory and therefore have no guide as to which time period is proper. Any period is as good as any other, and there is no possible resolution of the matter in the context of a rate case. There is simply no way to use more or better information to focus in on the true cost of capital.

Q. Why is it important to use financial theories that allow an objective way of dealing with the uncertainty involved with gauging investors' expectations?

A. Gauging investors' future expectations contains an unavoidable element of uncertainty. There is no direct and reliable way to learn today's cost of capital for the utility in question. Our indirect methods use models with simplifying assumptions and require the use of data that may not always be accurate or timely. That is, given a model's simplifying assumptions, the data used may cause us to think that investors are overly ambitious for one company and the reverse for another. The models we use should find a way of resolving this uncertainty objectively, because it does little good to use a financial model that leaves us with a 250 basis point range and no way to choose within it.

This indeed is the practical criterion that separates the usefulness of the two most popular financial theories used in rate cases—the DCF and the CAPM. The DCF renders a cost of capital estimate for each company in a proxy group. Some might seem a bit high and others a bit low, but the individual company results have objective "measures of central tendency," such as means and medians. This is not true for the CAPM. The CAPM is the sum of two components: (1) a company-specific risk premium; and (2) a "risk-free" rate applicable to all companies. There is a wide variety of risk-free rates from which to choose (*e.g.*, long-term/short-term) for which theory gives us no unambiguous guide. Furthermore, because the same risk-free rate applies as an additive term to all companies' cost of equity estimates, there is no measure of central tendency in the result. In short, we cannot resolve the question of uncertainty surrounding short-term versus long-term rates by repeated sampling. In the end, the analyst has to choose a risk-free rate that drives the results—precisely the type of choice that limits the model's objectivity and effectiveness. Indeed, this is the principal reason I avoid the CAPM as a primary ROE method in cases where it has not been deemed a required element of rate filings.

Q. What specific issues do you address in your testimony?

A. First, I summarize my findings and discuss what is meant by the term "fair rate of return" on equity. Second, I describe the DCF method that constitutes my principal method for determining that return. Third, I present my DCF analysis for Duquesne's electricity operations. Fourth, I perform a reasonableness check on my recommendation. Fifth, I explain why a market-to-book ratio greater than one does not imply that the Company is over-earning its expected rate of return. Finally, I address the issue of stranded cost recovery and explain why establishing a Competitive Transition Charge (CTC) recovery mechanism does not reduce the risks the Company has borne historically and therefore no reduction in overall return from the level I recommend is warranted.

II. SUMMARY AND BACKGROUND TO THE DETERMINATION OF A FAIR RATE OF RETURN ON EQUITY

A. Summary of Conclusions Regarding the Fair Rate of Return on Equity

Q. Please summarize your conclusions regarding the fair rate of return on equity for Duquesne's electricity operations.

A. The fair rate of return on equity that I recommend for Duquesne is **11.65 percent**. My recommendation results from a DCF analysis performed on a proxy group of U.S. electric utilities that are comparable to Duquesne's electric operations.

B. Background to the Determination of the Fair Rate of Return on Equity

Q. What do you mean by "fair rate of return on equity?"

A. The essence of traditional public utility ratemaking—the "regulatory compact"—has been that utilities like Duquesne have been protected by franchise against certain specific and limited types of competition. In return, the utility has accepted the obligation to provide service, on just and reasonable terms. The utility also accepted the duty to reasonably anticipate the future needs of its customers and to make whatever investments it judges necessary in order to meet those needs as efficiently as possible. Finally, the utility accepted that prices would be set so as to recoup operating costs plus a reasonable profit. For a public utility, reasonable profit, under the law and in the financial world, has been defined as a rate of return sufficient to attract capital.

The capital attraction—or "opportunity cost"—standard has been key in determining the fair rate of return for public utilities. When investors make their funds available to a utility, they are foregoing the option of using those funds for some other purpose (either current consumption or another investment). They also are putting their funds at some risk. In return for both foregoing current consumption and incurring risk, utility investors require a return on their funds. This return to investors is a cost to the utility—the "*cost of capital*." In order for the utility to compensate its investors adequately for the current consumption foregone and the risk incurred, the utility must be allowed, as a component of its rates for service, a *fair rate of return* that covers the cost of capital.

Q. Does the way you have just defined the concept of fair rate of return on equity comport with its traditional definition?

A. Yes. The traditional standard for a fair and reasonable return was established by the United States Supreme Court in its *Hope* decision (*Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)), where it stated:

> …the return to the equity owner should be *commensurate with returns on investments in other enterprises having corresponding risks.* That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and attract capital.* (Emphasis added.)

This often-quoted passage from the *Hope* decision, besides providing a legal standard for determining the fair rate of return, comports precisely with the opportunity cost standard for determining the fair rate of return that covers the utility's cost of capital.

In an earlier case, *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679, 693 (1923), the Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

Furthermore, the Supreme Court stated in *Bluefield* that establishing an insufficient return on invested capital denies shareholders the Constitutional right of due process under the Fourteenth Amendment.

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment.

Q. Has the traditional regulatory compact been changing over time?

A. It has not changed regarding the return that investors are due on their invested capital. It has changed, however, regarding the extent to which utility operations are regulated at all.

Q. Please explain.

A. Deregulation has been implemented in many industries throughout many countries in the past 20 years. The electric industry has not been immune to these changes. Technological changes, increased competitive pressures, and low fuel costs have made deregulation a possibility in the industry and successful deregulation in other industries has created demand for it.

Most states have begun the process of inquiring how the electric industry within its borders can be restructured; a few are well on their way. In its Electricity Generation Customer Choice and Competition Act, Pennsylvania has declared that electricity generation can be opened to competition while transmission and distribution must remain regulated. How this will be implemented and how issues such as stranded costs will be dealt with will be addressed in this proceeding. One point to keep in mind, however, is that notwithstanding the change in the nature of electricity regulation in Pennsylvania, the Act is consistent with the traditional regulatory compact insofar as it allows Duquesne and the other electric utilities the opportunity to recover the opportunity cost of the capital devoted to regulated activities.

Q. Does the traditional concept of fair rate of return apply to all of the capital raised by the utility from investors, or just the common equity component?

A. It applies to all of the capital. This includes a company's common stock equity, preferred stock equity (if any) and debt, both long and short-term.

Q. Why, then, does your testimony deal with the fair rate of return on equity only?

A. My testimony focuses only on the equity return component because, among all of the aforementioned investor-provided capital, for Duquesne or any other utility, the cost of common equity capital is the only one which is not observed directly.

In the abstract, the overall cost of capital is comprised of three elements and three returns. Each of the six components is needed to develop the overall fair rate of return for a utility. They are: the proportions of debt, preferred stock and common stock in the capital structure and the individual fair returns pertaining to each.

The proportions of debt, preferred stock and common stock in the capital structure are directly observable. In addition, the fair returns on debt and preferred stock are also directly observable. Only the fair rate of return on common equity is not directly observable. The individual fair rate of return on common equity must be derived indirectly with reference to other market indicators. For this reason, my testimony focuses on the determination of the fair rate of return on common stock equity only.

Q. How are the individual fair returns or costs of capital pertaining to debt and preferred stock observed directly in a rate case?

A. Fixed payment obligations accompany both debt and preferred stock: interest on the former, preferred dividends on the latter. It is not a difficult task to calculate the dollars needed to cover interest or preferred stock dividend payments either currently or over the period of time in which the rates in question for a utility will be in effect. The *embedded* cost of debt and preferred stock proceeds directly from these calculations.

The reason I highlighted the word "embedded" is that, for debt and preferred equity, all that is needed in a base rate case is the embedded cost of these financial instruments (or, stated another way, the payments to investors proceeding from existing agreements accompanying the existing bonds and preferred shares). This is why there is seldom any substantive disagreement among parties in rate cases concerning the embedded cost of debt and preferred equity capital. All one has to do is compare the promised interest and preferred dividend payments against the company's proceeds from the sale of those securities. The current market is irrelevant for such embedded cost calculations.

Q. Is there a current (as opposed to embedded) cost of debt and preferred equity capital which can be observed in the market?

A. Yes. Since the schedule of interest and preferred stock dividends is known, and since the current market price for these financial instruments (a bond or share of preferred stock) is known, then the current (as opposed to embedded) cost of capital for both types of financing is known and observable. The current cost of debt and preferred stock capital, reflecting investors' required return, is the discount rate that equates the present value of the known stream of interest (and principal) payments, or preferred dividend payments, with the observed price of those securities.

In other words, a relatively straightforward way of determining the current cost of debt and preferred equity securities is to observe the known market price and the known stream of interest and preferred dividend payments, and calculate the discount rate that equates the two. The derived discount rate is equivalent to the current cost of debt and preferred equity capital.

Q. Can the current cost of common equity capital be calculated the same way?

A. No. An essential component to that calculation was knowledge of the (fixed) interest and preferred stock dividend payments. Dividend payments on common stock equity are not fixed, nor is their growth rate measured with certainty. They are generally expected to grow as the company in question grows. This growth rate is not observable—the growth rate is embodied in unobservable equity investor expectations regarding the future performance of the company in question. Because this growth rate is not observable, the future stream of dividend payments is not known. There is therefore no known stream of payments that may be used directly to find the discount rate equating the present value of the future stream of dividend payments with the observed common stock price.

Q. How can the cost of common equity in Duquesne's capital structure be estimated?

A. One way of estimating the cost of equity capital (and generally the most popular method among regulatory commissions) is to determine what stream of common dividends is expected by investors. This entails observing the current dividend and then engaging in the difficult task of estimating what investors expect regarding the growth in that dividend. After the growth expected by investors is estimated, the cost of common equity can be calculated by equating the present value of the estimated stream of dividend payments with the observed common stock price. The calculated cost of capital resulting from this method is entirely dependent on the quality and dependability of the estimates of investor expectations regarding dividend growth. This type of estimation, which I shall later describe in detail as the DCF method, is the method I use for estimating the fair rate of return for Duquesne.

C. Estimating the Cost of Equity Capital

Q. How did you determine the fair rate of return on equity for Duquesne that is consistent with the standards you described and that addresses the difficulties inherent in estimating the cost of capital?

A. There are two basic components to estimating the cost of capital: theoretical and empirical. I focus on both of these aspects of my cost of capital calculation.

The theoretical component relies on the standard financial literature to develop cost of capital methods that are consistent with what we know and observe about the way financial markets work. All cost of capital models that appear in the financial literature are the result of such theoretical investigations. The most important theoretical consideration when determining the cost of capital for Duquesne is to employ a method that provides an accurate reflection of the market for the Company's common stock.

The empirical component includes the collection of the data to be used with the theoretical cost of capital methods. The most important empirical consideration is to gather data that are: (1)

consistent with the theoretical models employed; (2) timely; and (3) unbiased. It also is important that the calculations made with the empirical data be reliable and stable. In other words, the resulting cost of capital measure should not be highly sensitive to minor or judgmental changes in the type or source of the data used.

Q. What theoretical method do you use in your evaluation of Duquesne's cost of capital?

A. As I mentioned in the previous section, I employ the DCF method. The DCF method makes use of the relationship between the current stock price and the expected future stream of dividends in order to calculate investors' estimated discount rate, or cost of equity. The DCF method has a long history of use in the effort to derive the cost of equity for both regulatory and market investment purposes. It is a sound, reliable, easy-to-understand and easy-to-reproduce method for determining the fair rate of return. Furthermore, it is unique among rate-of-return determination methods in that the model's results become stable and reliable when it is applied to a group of similar utilities.

III. THE DCF METHOD

A. Description of the DCF Method

Q. Please describe the DCF method.

A. The DCF method is used to estimate the cost of common stock equity by determining the present value of all future income expected to be received from a share of common stock. As such, the DCF method is the common stock equity analog to the way in which debt and preferred stock equity cost rates are calculated. With the DCF method, the cost of common stock equity is computed as the discount rate that equates a stock's current observed market value with the present value of all future expected returns from holding the common stock (*i.e.*, dividends and capital gains). The prevailing common stock price is assumed to reflect investors' expectations of the value of common stock, including future dividends and price appreciation.

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[2] The research performed by subsequent writers (including Gordon himself) resulted in the equation known as the "Periodic" DCF model. The "Periodic" DCF model generally expresses k_e, the cost of the common stock equity portion of total capital, as a relationship between the prevailing price of common stock equity, P_0, current dividends, D_0, and the dividend growth rate, g. Following is a formal statement of the "Periodic" DCF model.[3]

$$k_e = \frac{D_0 * (1+g)}{P_0} + g$$

$$k_e = \frac{D_1}{P_0} + g$$

Where: **(1)**

P_0 = price of stock

D_0 = previous dividend paid

k_e = cost of equity

g = dividend growth rate

D_1 = $D_0 * (1+g)$

This "periodic" or annual version of the DCF model has been very popular in regulatory rate-of-return proceedings. In order to use the model properly, however, it is important to reflect accurately how dividends are paid and how they grow. This model has two significant abstractions from the reality of dividend payments. First, it assumes that dividends are paid annually; and second, it assumes that dividends grow continuously from period to period. In fact, most utilities pay dividends quarterly and increase their dividends only once a year, if at all.

A different version of the DCF model avoids these abstractions. Specifically, the "Quarterly" DCF model recognizes quarterly dividend payments and allows these payments to grow at a

[2] See: Myron J. Gordon, *The Investment, Financing and Valuation of the Corporation*, (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

[3] The derivation of this model appears in **Exhibit JDM - 2** of my testimony.

constant rate from one quarter to the corresponding quarter in the following year. It is the proper model for the purpose of calculating the cost of the common stock equity portion of total capital, in terms of investors' required return, for firms that pay dividends quarterly and normally increase dividends only once a year, if at all.

Q. Is the "Quarterly" DCF model the proper model for calculating the cost of the common stock equity portion of total capital in this rate case?

A. No. It is the proper way to calculate the total return required by *investors*, but that is not the appropriate rate of return to apply to rate base in proceedings such as these. For ratemaking purposes, the rate of return should be developed from the perspective of the utility, not from the perspective of the investor.

Q. Please explain the difference.

A. The difference is the reinvestment of quarterly dividends paid by the utility. Because dividends are paid quarterly instead of annually, investors can choose how they wish to reinvest the dividends to obtain their total return for the year. They can, for example, reinvest in the equity of the utility. Alternatively, they can invest in the securities of another company. For this reason, then, the reinvestment of quarterly dividends (implicit in the quarterly DCF model) is the appropriate model when considering total return from the perspective of investors. The utility, however, does not control the reinvestment decisions of investors and therefore is only responsible for providing the fair rate of return as calculated in the "periodic" DCF model above. If the utility provides the fair rate of return, investors can reinvest the utility's dividends in a manner that will allow them to reach their total required return.

In other words, the cost of the common stock equity portion of total capital developed in the "Quarterly" DCF model accurately mirrors *investors'* current return requirements on common stock equity. It does not, however, reflect the *utility's* fair rate of return that must be applied to the rate base to yield the revenue requirement necessary to give investors what they require.

When the appropriate adjustments are made to reflect the perspective of the utility, the quarterly model reduces mathematically to the "Periodic" DCF model I presented above. In **Exhibit JDM - 2**, I present the calculations that confirm this. Thus, the "Periodic" or "Annual" DCF model is the one to use in this proceeding.

Q. Are investors' expectations with regard to total return and expectations regarding dividend growth synonymous?

A. No. Both the "periodic" and the "quarterly" DCF models incorporate investors' expectations regarding the growth in dividends. Investors' expectations regarding total annual return relates to the "quarterly" DCF model that incorporates the effects of reinvesting quarterly dividends.

B. Selection of Comparable Company Group

Q. Did you use a comparable group of electric utilities in your determination of the fair return on equity for Duquesne?

A. Yes. I employed a group of 17 electric utilities that are similar in many respects to Duquesne.

Q. Please explain why such a comparable group of companies is useful in this context?

A. There are three practical reasons not to rely solely on one firm in determining the fair rate of return on equity, even if company-specific data are available. They are: (1) the use of a group of companies produces a more *reliable and unprejudiced* estimate of the current cost of capital required by capital markets; (2) the computation of comparable group fair rate of return estimates gives substance to the *Hope* decision's finding that a reference should be made to return on *investments with corresponding risks*; and (3) the regulatory process in a particular jurisdiction affects investor expectations regarding the particular company whose fair rate of return is being set, leading to a problem of "*circularity*." This is particularly true in states where primary weight is given to the "sustainable dividend growth rate" in determining a company's fair rate of return on equity. This growth rate is very much a function of the proceeding where the growth is supposedly being estimated. The use of a proxy group will attenuate the circularity problem.

Q. Why should "circularity" be a concern to the regulator?

A. Circular reasoning has long been found to be a serious problem in the determination of a fair rate of return for investors. For example, the principle of "fair value" rate regulation (which dominated public utility regulation at both the state and Federal level before the 1940s) gave way to "cost-based" rate regulation in large part because of a problem of circularity. As Professor Bonbright stated: "Any attempt to test the fairness of the rates by reference to a valuation of the properties (which depends on rates themselves) is an attempt to reason in a circle, or, if you like, to put the cart before the horse."[4]

Whenever a commission uses a formula for determining a fair return that depends on investors' expectations of future growth, circularity arises because we know that investors' expectations depend on the return that the regulator is expected to allow. The path of supposed causation proceeds in *both directions simultaneously*, which, of course, is the source of circular reasoning. Another example of the circularity problem in the determination of the fair rate of return is the practice of using other public utilities' returns in a "comparable earnings" analysis. If the past earnings of the comparable group are low, it will likely result in a lower awarded rate of return on equity for the company under consideration. This company will, in turn, become part of another comparable group and will contribute to lower rates of return for other companies, creating a cycle from which it is difficult to escape.

By the same token, there is a circularity problem inherent in using a sustainable dividend growth formula for calculating the dividend growth in a DCF analysis when the principal components of that growth (*i.e.*, the expected return and the retention ratio) are a function of the rates to be awarded. This practice is an impediment to the objective and impartial determination of a fair rate of return for a regulated utility.

Proxy group DCF calculations are far less likely to depend on the anticipated return granted in this case and, therefore, are far less likely to be susceptible to problems of circularity.

Q. Which are the comparable companies you employ in your DCF analysis of Duquesne's electric operations?

A. The 17 companies are listed in **Exhibit JDM - 3.**

Q. What criteria did you use to determine that the companies you chose are "comparable" to Duquesne's electric operations?

A. I defined what I conclude are the minimum number of criteria that would satisfy two basic objectives. The first basic objective was to assemble a group of companies with publicly-traded stock that were representative, on average, of the business risk faced by Duquesne's

[4] J.C. Bonbright, *Principles of Public Utility Rates*, (New York: Columbia University Press, 1961), 164.

electric operations. The second basic objective was to assemble a group of companies with stock price and dividend payment data that could be readily applied to the annual DCF model.

Q. What criteria satisfy your first basic objective—that of mirroring the business risk faced by investors in Duquesne?

A. Duquesne operates a medium-size electric utility. The following two characteristics help to define the business risks faced by those who invest in an electric utility company and are recognized by investment analysts as pertinent factors in evaluating the risk of an equity investment: (1) type of business, in this case a regulated electric utility; and (2) size.

Given these characteristics, I used two criteria to exclude companies from the proxy group. *First*, I selected those companies that derived at least 85 percent of operating revenues from electricity sales. The average proportion of total operating revenue from electric activity in 1996 for the proxy group was 95.4 percent. Duquesne derived 100 percent of its operating revenues from electric activities. *Second*, I restricted the group of companies to those with a total capital less than $10.0 billion. Some of the utilities in the proxy group have a higher total capital than Duquesne and some a lower total capital, but my goal (as stated above) was to create a proxy group that, *on average*, is representative of the business risk faced by Duquesne. The average total capital for the group was almost $3.5 billion and Duquesne's was about $3.1 billion.

Q. What criteria satisfy your second basic objective—to assemble a group of companies with stock price and dividend payment data that could be readily applied to the annual DCF model?

A. I established two additional criteria to try to ensure that the data collected from the assembled proxy group companies can be used reliably in a DCF analysis. *First*, I restricted the group to utilities for which no explicit concern was raised in my financial data sources regarding the ability of the company to maintain its existing dividend. Because the DCF model I employ assumes a constant long-term dividend growth rate, it is inappropriate to apply the model to companies where a dividend decrease is expected. Such an expectation will surely affect the price that investors would be willing to pay for the stock of such a company, which would render the use of the periodic, single growth rate DCF model suspect. *Second*, I excluded from the analysis any companies that are the known targets of possible takeovers. Tender offers associated with takeovers generally affect stock prices in a temporary way unrelated to the overall cost of capital and make the use of those stock prices in a DCF analysis suspect.

Q. Is it true that Duquesne is currently involved in a merger?

A. Yes.

Q. Is it appropriate then to use this criterion to calculate Duquesne's fair rate of return on equity?

A. Yes. Whether or not Duquesne is involved in a merger does not affect its right to receive a return consistent with investments of similar risk.

Q. Please summarize the criteria you selected.

A. The following table lists the four criteria I formulated, categorized by the objectives.

OBJECTIVE I

To mirror the business risk faced by Duquesne's electric division

Criterion 1	**Select companies that derive at least 85 percent of total operating revenues from providing electricity sales.**
Criterion 2	**Select companies with a total capital less than $10.0 billion.**

OBJECTIVE II

To assemble a group of companies with stock price and dividend payment data applicable to the annual DCF model

Criterion 3	**Select solvent companies that do not anticipate dividend decreases.**
Criterion 4	**Select companies that are not known targets of possible takeovers.**

Q. What was the result of applying your criteria?

A. The result of applying the four criteria was that I developed a group of 17 electric utilities listed in **Exhibit JDM - 3** that I conclude have a degree of business risk comparable to Duquesne's electric operations, if not slightly less. **Exhibit JDM - 4** explains how the proxy group was chosen. The proxy group may be slightly less risky than Duquesne, on average, because it contains electric utilities that do not operate nuclear generating facilities. Nuclear facilities are generally viewed as increasing a utility's risk and I regularly use this as a factor in selecting proxy groups. At this particular time, however, many electric utilities are involved in merger activities and are therefore not potential candidates for my proxy group based on the merger criterion. To ensure that I had a proxy group of a sufficient size to produce reliable and stable results, I dropped the nuclear facilities criterion in this particular case. By dropping the criterion, the proxy group analysis produces a more conservative estimate of the cost of equity for Duquesne.

C. Inputs into the DCF Calculations

Q. Please turn now to your description of the data you use to determine the fair rate of return for Duquesne's electric operations.

A. As I stated previously, it is important to use data that are: (1) consistent with the theoretical DCF method; (2) timely; and (3) unbiased. It is also important that the calculations made with the empirical data be reliable and stable.

The DCF analysis requires three data inputs: (1) current stock prices, P_0, (2) the current annual dividends, D_0, and (3) estimated dividend growth rates, g. I will deal with each of these DCF inputs in turn.

1. Calculation of the Stock Price, P_0

Q. What data did you use for the stock price input, P_0, in your DCF calculations?

A. I used stock prices obtained from the *Wall Street Journal*. It is my normal practice to use stock prices on the latest day consistent with the filing, because only the latest stock prices are consistent with up-to-date investors expectations. This is because the informative value (with regard to investor expectations) of yesterday's stock prices will be completely superseded by today's stock prices. This is a widely held tenet of efficient markets. If today's stock prices embody all of the expectations regarding the value of those stocks, then yesterday's prices represent "old news." Yesterday's prices, therefore, are useless as a gauge to investors' current expectations.

Nevertheless, I have been informed by counsel that the Commission tends to employ a yearly average for stock prices in DCF calculations. In other jurisdictions (*e.g.*, New York, which traditionally uses a 20 day average stock price), I have adopted such conventions as long as they represent reasonable and reliable precedent—that is, not subject to opportunistic change just because of recent stock market activity. Therefore, in this case I have employed a yearly average of the 52 most recent weekly closing prices (with the most recent weekly close being July 18, 1997).

Q. Did you adjust the observed stock prices?

A. Yes. I performed an "ex-dividend date" adjustment on all of the stock prices to remove the known effect that the next quarterly dividend payment has on the stock price. Failing to remove this effect would make the stock price used inconsistent with the DCF formula.

This adjustment is necessary because of the assumption in all standard DCF models that the next quarterly dividend will be received one full period from the date the stock price is measured. The problem with this assumption is that the next quarterly dividend is usually closer than one full quarter from the day the stock price is observed. This affects the stock price in a known way and must be corrected in order to avoid a downward bias in the calculated result.

Q. What is the ex-dividend date, and how can ignoring it bias the DCF calculations downward?

A. The ex-dividend date is the date on which the right to the next dividend no longer accompanies a stock. In other words, if you purchase a share of stock the day before the ex-dividend date, you will receive the next quarterly dividend paid by the Company. If you purchase that share one day later, you will not receive that dividend. Because dividends are an important part of the return to utility shareholders, and in view of the relatively high payout ratios involved, the ex-dividend date is an important determinant of the stock price. Utility stock prices, like other stock prices, are observed to drop by an amount approximately equal to the quarterly dividend on the ex-dividend date.[5]

All of the DCF models I have outlined in my testimony are applicable *only on the ex-dividend date.* In other words, all of these models assume that future dividends begin a full period hence. Failure to adjust the stock price observed at an arbitrary date to account for the ex-dividend date will bias the applicable stock price upward (by approximately the amount of the "accrued" portion of the quarterly dividend), and the resulting DCF calculation downward.

Q. Have any other jurisdictions with which you have experience accepted the ex-dividend date adjustment?

A. Yes. The New York Public Service Commission has performed such adjustments as a regular component of its determination of the fair rate of return. When it accepted the adjustment for the first time, in a case where I participated as the rate-of-return witness, the Commission used the following reasoning:

> The Judge adopted a company proposal, to which staff agreed, which increases the yield component in the DCF calculation to account for the temporary stock price increases as quarterly dividend payment dates approach . . . [The adjustment] is designed to produce the correct yield given the DCF formula. . . . [T]he method has been sufficiently developed on this record to warrant adoption of the adjustment.[6]

Q. Why do you reference New York?

A. Because New York was the only state in which I testified where the issue was contested with sufficient vigor by both sides that the Commission felt obliged to rule that the adjustment was reasonable.

Q. Should the adjustment should be performed in Pennsylvania?

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[5] A discussion of the importance of the ex-dividend date appears in most financial texts. See for example: E.F. Brigham, *Financial Management Theory and Practice,* 3rd Edition, (New York: The Dryden Press, 1982), 687. Empirical evidence on this phenomenon can be found in articles written by J.A. Campbell and W. Beranek, "Stock Price Behavior On Ex-Dividend Dates," *Journal of Finance*, 10, 4, (December 1955), 425-429; D. Durand and A.M. May, "The Ex-Dividend Behavior of American Telephone and Telegraph Stock," *Journal of Finance*, 15, 1 (March 1960), 19-31; and E.J. Elton and M.J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," *Review of Economics and Statistics*, (February 1970), 68-74.

[6] State of New York Public Service Commission, (The Brooklyn Union Gas Company) Opinion No. 90-29, October 17, 1990, 21-22.

A. Yes. Wherever the DCF model is used, it assumes stock prices are one full period away. If the adjustment is not made, whether in New York or Pennsylvania, the analysis will always yield an underestimate of the fair rate of return on equity.

Q. How precisely do you make the adjustment in the stock price?

A. I traditionally make the adjustment by removing from the stock price the portion of the dividend which has already accrued. I make this adjustment to the P_0 term before performing the DCF calculations for a proxy group. In cases where I employ a single day's stock price, the adjustment is straightforward. That is, I subtract from the stock price a proportion of the last dividend payment. That proportion is the number of days since the last ex-dividend date, divided by 90 (*i.e.*, a full quarter).

In cases where I employ an average of stock prices, more calculations are required. However, as long as the ex-dividend dates are relatively evenly spread across the quarter for the members of the proxy group, a short-cut is simply to make an average ex-dividend date adjustment for all the companies in the group. In this case, I first checked to see whether the short cut provided a similar figure to the exact adjustment for stock prices measured on July 17, 1997. **Exhibit JDM - 5**, page 1 of 2, shows that the short cut produced exactly the same results (*i.e.*, to the penny). That illustration, on page 1 of 2, confirms the reasonableness of using the same method for the 52 week average, shown on **Exhibit JDM - 5**, page 2 of 2.

2. Calculation of the Dividend D_1

Q. How did you measure the dividend, D_1?

A. The DCF model requires that $D_1 = D_0 * (1+g)$, where D_0 is equal to the sum of the four most recent dividend payments. Thus, my starting point was to obtain the data for D_0. I obtained the sum of the past four quarterly dividend per share payments from *Value Line Investment Survey*.[7] I used the sum of the four most recent dividend per share payments for

[7] Data for the electric utilities were taken from *Value Line Investment Survey*, Edition 1, (June 13, 1997), Edition 5, (April 11, 1997) and Edition 11, (May 23, 1997). Each edition, updated regularly, provides data for a number of years for electric utilities from a particular region of the country.

each company in the proxy group, which is the D_0 term shown on **Exhibit JDM - 6**, column (e).

3. Calculation of Growth, *g*

Q. How did you estimate the dividend per share growth term, g?

A. I used two different prospective growth measures to estimate dividend growth from which I then took the simple average. The first is a measure of sustainable growth that examines projections of the separate components of dividend growth—that is, retained earnings and expected returns to book equity, as well as the possibility of issuing new shares at prices in excess of book values. The second measure is calculated using the forecasts of earnings per share published by *Value Line* in the issues listed above.

Q. Please describe the first method you used to calculate growth for the companies in your comparable group.

A. The first method is known as either the "retention growth" or "sustainable growth" method. This method produces a forward-looking, sustainable growth rate by multiplying the fraction of earnings expected to be retained by a company by the expected return on book equity. The sustainable growth method also allows for growth stemming from new issuances of stock at premiums over book value. This is a valid way of estimating future dividend growth, because future growth in the dividend can only occur if: (1) a portion of the expected equity return is reinvested instead of being paid out in the form of dividends; or (2) if new common stock is issued at prices above current book values (causing existing shares to appreciate in value).

I estimated a sustainable growth rate for each company using the following formula:

$$g = B * R + S * V \tag{2}$$

Where:

B = expected retention ratio

R = expected return on equity

S = percent new equity expected

V = 1 - book to market ratio

This formula for estimating sustainable growth is explained in more detail in **Exhibit JDM - 7**. This theoretical growth measure shows that investors can expect growth through both retained earnings and the sale of new stock at a premium of book. For all the publicly-traded stocks in the comparable company group, both forms of growth can currently be expected by investors, as the market-to-book ratio for all is above one. If the $S*V$ term is ignored in the sustainable growth calculation, the resulting formula would not be an accurate representation of investor perceptions of growth.

Q. Is the use of forecasts in your second method, like those appearing in *Value Line,* advisable?

A. Yes. The practice of using forecast growth rates provides a good basis for estimating the long-term growth of the utility. Financial analysts exert considerable influence over the many investors who do not possess the resources to make their own forecasts. The accuracy of these forecasts, in the sense of whether they turn out to be correct, is not the issue as long as they reflect widely held expectations.

Analysts' forecasts are often criticized on the ground that it is very difficult to forecast growth rates accurately in the short term, let alone in the long term. However, this general objection is irrelevant to a DCF analysis because this method is based upon present investor expectations. Widely distributed forecasts influence both the current stock price and DCF cost of equity, not what the future will actually turn out to be.

Q. Are the five-year annual projected growth rates in earnings published by *Value Line* reasonable indicators of long-term growth?

A. They are reasonable in the context of proceedings in which rate of return is being examined. It would be naïve to assume that the growth rates forecasted by *Value Line* are applicable far into the future. However, there are two strong reasons for employing such forecasts in the present proceeding. First, to the extent that investors employ forecasts like those published by *Value Line* as long-term growth rates, these forecasts accurately reflect the current expectations of long-term growth included in the cost of capital. Second, *Value Line* forecast growth rates may not be substantially different, on average, from what investors believe long-term growth prospects to be, given that the forecast is widely distributed in the financial community. In addition, a study by Brown and Rozeff shows that *Value Line* analysts make better forecasts than could be obtained by employing historical data only.[8]

The growth rates discussed above can be found in **Exhibits JDM - 8** through **JDM - 10**.

4. Selling and Issuance Cost Adjustment

Q. Did you make any adjustments to your DCF results?

A. Yes. I made an adjustment for selling and issuance costs when calculating the DCF costs on **Exhibit JDM - 6**.

Q. Why did you make such an adjustment?

A. The issuance of common equity, as well as long-term debt and preferred stock, involves costs. These costs are often measured as a percentage of the total debt, preferred equity or common equity issuance. Because of issuance costs, the net proceeds of a debt, preferred equity or common equity issuance will always be less than the total purchase price of the securities issued. Unless an adjustment is made to reflect this phenomenon in the fair rate of return—an adjustment consistent with the issuance cost adjustment already made for debt and preferred stock—the resulting fair rate-of-return calculations will be too low. The same problem with a return too low would result if selling and issuance costs were ignored in calculating embedded debt costs.

Q. Is such an adjustment generally made by regulators?

A. Yes. An adjustment to factor out selling costs is made as a traditional part of computing the embedded cost of debt and preferred stock—even though it is often contested where equity is concerned.

Q. Please explain.

A. Basing required returns on net, rather than gross, proceeds is standard regulatory practice when the capital is in the form of debt or preferred stock. It is inconsistent—and the source of

[8] L.D. Brown and M.S. Rozeff, "The Superiority of Analyst Forecasts As Measures of Expectations: Evidence From Earnings," *Journal of Finance,* 33, 1 (March 1978), 1-16.

improper DCF calculations—to exclude the same type of issuance cost allowance from outstanding common stock balances if those costs were incurred in the issuance of that common stock and were not reflected as a current expense in rates at the time the issuance was made. For long term-debt and preferred stock issuances, these costs are capitalized by calculating a required rate of return on the net proceeds to Duquesne. It would be inconsistent to allow the capitalization and collection of these costs on long-term debt and preferred stock issuances and not to allow the collection of the same kind of costs on common stock issuances.

Q. What is the most common way for regulatory commissions to compensate for issuance costs?

A. The most common way to compensate utilities for necessary issuance costs related to common stock, as well as for preferred stock and long-term debt, is to allow a return *on* these costs for any one year and a return *of* these costs over the life of the issue. For common stock, because the life of the issue is, in essence, perpetual, the return component to recover the return on these costs is permanently a part of the return on equity. The only way these costs will "go away" is if they are paid off as a current expense. Failing to compensate a utility for its issuance costs will assure the under-recovery of its prudently-incurred costs of raising capital.

Q. Is there more than one way that a commission can deal with selling and issuance costs?

A. Yes. A commission appropriately can handle these costs in one of three ways. *First*, the commission could allow the company to recover these costs automatically in the year they are incurred as an expense component of the revenue requirement (or the expense could be amortized over a number of years—with a return on the outstanding balance).

Second, a commission could allow the issuance costs to be included in the rate base (like the treatment of interest charges on construction work in progress). This would allow the company to earn a return *on* the costs, as opposed to a return *of* the costs.

Third, the commission could adjust the cost of capital upward over the life of the issue. This adjustment in effect allows the company to earn a return *on* the issuance costs, even though the costs are not in the rate base. The financial result and the revenue requirement are the same as for the second method.

All of these methods would compensate the utility for the actual issuance costs incurred.

Q. Are you aware that the Commission in Pennsylvania does not routinely allow flotation cost adjustments?

A. Yes. I have noticed in previous decisions that the Commission feels flotation costs are already reflected in the market-derived cost of equity. However, I have found no evidence in the financial literature that this is the case. On the contrary, substantial selling and issuance costs for equity are a fact—that is, when a share of stock is sold for $10.00, the utility takes in a percentage less than that (principally on account of underwriters fees, the same source of the principal expenses for debt and preferred issues).

Utilities like Duquesne collect the costs of issuing debt and preferred stock as a part of traditional regulatory practice. There is no basis, in my opinion, for treating common stock issuance costs separately. Therefore, in **Exhibit JDM - 6**, I make the adjustment consistent with the collection of these costs when computing the DCF results.

Q. How have you made your issuance and selling expense adjustment?

A. It is proper to include an issuance expense return adjustment for the entire equity component of the capital structure.[9] Therefore, I used the conventional form of the issuance expense adjustment:[10]

$$r = \frac{D_1}{P_0 * (1 - f)} + g$$

Where: **(3)**

r = required return adjusted for issuance expenses

f = flotation cost percentage

[9] Support for using total common equity appears in: Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36.

[10] This formula appears in Roger A. Morin, *Utilities' Cost of Capital*, (Arlington Virginia: Public Utilities Reports, Inc., 1984), 106; and Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36.

For the purpose of choosing an appropriate value for f, the flotation cost percentage, I referred to a publication by Victor Borun and Susan Malley as well as information specific to Duquesne's most recent public equity issuances.[11] Borun and Malley conclude that total flotation costs for electric utilities are around 5.5 percent. As shown in **Exhibit JDM - 11**, the average of Duquesne's last three equity offerings is 4.44 percent. The average of the two is 5.0 percent, which I use as the issuance cost percentage for the DCF calculations in this case, according to the formula above.

Q. Please explain why the issuance expense adjustment should be made to total common equity.

A. Investors are entitled to earn the expected cost of capital on their investment. The DCF model illustrates that this expected cost is equal to dividend payments plus capital gains on the value of their shares. The cash paid in by investors is greater than the net proceeds that the company takes in. Therefore, the company must earn a greater return on the smaller net proceeds balance to compensate investors adequately for their expected cost of capital. But the money paid to the investors in any year, the dividend, reflects only a portion of the returns on equity. The other portion is represented by retained earnings, or the funds used to finance future growth and future dividends. If retained earnings do not receive a selling and issuance return adjustment, they will not grow at a rate sufficient to allow for the payments of dividends at investors' expected growth rate in the future, and the company will not earn its true cost of capital.

D. Empirical DCF Calculations for Proxy Group of Electric Companies

Q. How did you calculate a DCF cost of equity for the proxy group of electric utilities?

A. Using the ex-dividend date adjusted stock prices for a 52-week closing average, ending July 18, 1997, the most recent four actual dividend per share payments, the average of the sustainable growth and forecast earnings growth, and the issuance cost method shown above, I estimated a cost of equity for the proxy group of **11.65 percent** as shown in **Exhibit JDM - 6.**

[11] Victor M. Borun and Susan L. Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly*, (February 20, 1986), 33-39.

IV. REASONABLENESS CHECK

Q. Do you think your return on equity recommendation should be compared to some other results for reasonableness?

A. Yes.

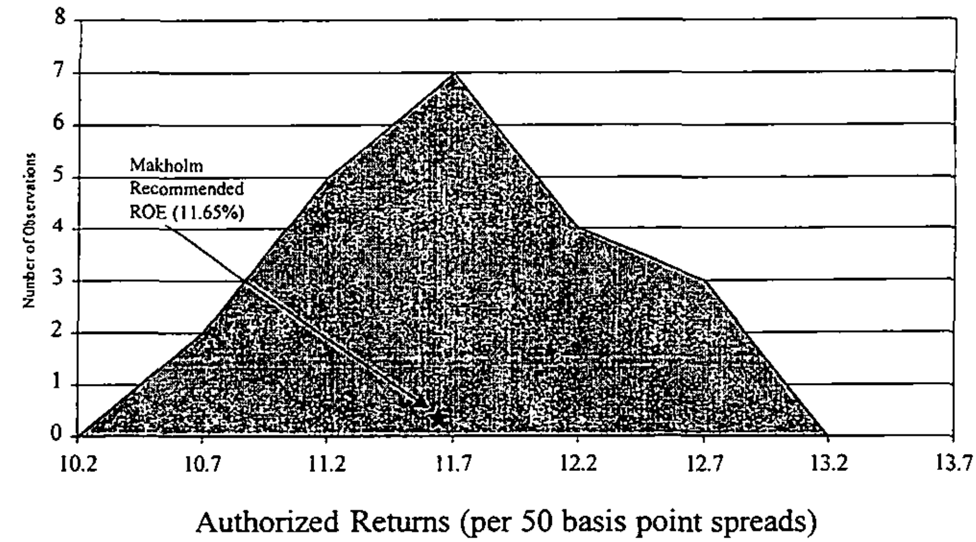
Q. What check of reasonableness of your return recommendations have you performed?

A. I reviewed the most recent rate-of-return decisions for electric utilities listed by Regulatory Research Associates between April 1995 and March 1997.

Q. Please explain how you developed your check, the return-on-equity comparison.

A. **Figure 1** shows the range of electric utilities' returns on equity which have been authorized by regulatory commissions throughout the country between April 1995 and March 1997. My data base covers a total of 23 decisions. The figure also shows the number of decisions associated with each return on equity figure. I have indicated where my recommended return on equity of **11.65 percent** falls within the range of ROEs. **Exhibit JDM - 12** presents the individual state commissions' allowed returns that make up the figure.

Figure 1
Comparison of Authorized Returns on Equity



Q. What conclusions do you draw from the information presented in **Figure 1**?

A. My recommended return is near the mean and the median of the range of returns authorized by commissions throughout the country over the period April 1995 through March 1997, which suggests that my recommendation is reasonable.

V. MARKET TO BOOK RATIOS

Q. You have derived a cost of capital for Duquesne by reference to a proxy group. Do the common stock shares for the companies in that group generally trade above the book value for those companies?

A. The common stock shares currently trade at prices above book value for all of the companies in the proxy group.

Q. Does this mean the companies in the proxy group are earning excessive rates of return with respect to their cost of capital?

A. No. Except for a period in the late 1970s and early 1980s, when inflation was high and regulated rates failed to keep pace, this has been a common circumstance for electric utilities for decades.

Q. But if such utilities earned their allowed rate of return, would you not expect the value of the common stock shares to roughly equal the book value?

A. No.

Q. Why not?

A. Because the expectations of investors concerning the actual sources of their income come from a number of sources—only one of which constitutes the allowed rate of return multiplied by the equity rate base (*i.e.*, the standard ratemaking formula). Unregulated earnings, regulatory lag, and growth expectations, among other things, all contribute to investors' expectations of what they will earn when purchasing a share of utility common stock. To the extent that we see a persistent trend for utility common stocks to trade at prices above book value, these influences are clearly at work.

In **Exhibit JDM - 13**, I present a straightforward model of the factors that affect the market-to-book ratio. In that model, I provide a standard formula for the revenue requirement (*i.e.*, the ratemaking formula) along with the formula that shows simplified investor expectations of income. With such a model, it is easy to show that the market-to-book ratio will equal 1.0 only under a highly restrictive set of circumstances, including:

- Perfect regulatory foresight
- No regulatory lag
- No unregulated earnings
- New investment equals depreciation
- No error in setting the rate of return equal to the cost of capital.

Relaxing these assumptions drives a wedge between the market value and book value of common stock equity. Seeing that these conditions are highly unrealistic in practice, there is no reason to expect that, even on average, stock prices should equal book values for common equity. In fact, relaxing these assumptions, as explained in **Exhibit JDM - 13**, has a greater upward effect on expected earnings than downward, except in periods of high inflation combined with regulatory lag, as occurred in the late 1970s to early 1980s.

The conclusion from **Exhibit JDM - 13** is that there is no just reason for concluding that stock prices should equal book value for common equity. This is particularly true for a company like Duquesne where unregulated earnings are becoming a substantial part of the company's overall earnings. Indeed, when inflation is under control, a number of factors—including unregulated earnings—should be expected to keep market prices above book values. And that is what we observe in the stock market for electric utilities generally.

VI. STRANDED COST RECOVERY

Q. Should utilities like Duquesne be allowed to recover their "stranded" costs?

A. Yes. There are different perspectives that bear on the reasonableness of allowing companies like Duquesne to recover the costs occasioned by changing regulatory rules to encourage greater competition—competition that was not generally envisioned when the investments in question were made. Those perspectives deal both with regulatory principles in the United States and practicality of regulation generally. That is, they involve both the traditional legal standard I described at the outset of my testimony as well as the prospect for the Commission to maintain a regulatory regime into the future that serves the interests of its consumers.

There are good reasons for pursuing competition in the generation and dispatch of electricity. The efficiencies and cost savings that flow from such competition promise to be considerable. At the same time, however, the change in the nature of regulation will leave many electric utilities like Duquesne in the position of being unable to collect all of their existing electricity production costs (including a return on capital) in competitive electricity supply prices, *per se* (although there is no question that other mechanisms exist to allow collection of these costs—such as non-bypassable wires charges). Thus, the costs that we label "stranded" in this proceeding are stranded in terms of collection at one stage of the supply chain (*i.e.*, all generation costs cannot be collected in competitive generation prices), but not in total.

At the outset of my testimony I discussed the traditional legal and economic standards for gauging the adequacy of the remuneration for the capital employed by utilities in the public service. The fundamental principle espoused by the 1944 *Hope* decision is based on the concept of *opportunity costs* (which is the economic standard for compensation as well). That is, opportunity cost is the legal standard for remuneration allowed for capital to flow into the public service while still treating utility customers fairly. The opportunity cost standard focuses on the commensurate return that investors could have expected had they placed their funds in other ventures *instead* of public utility service. There is no way to construe the opportunity cost principle—which underlies the *Hope* decision—to mean that the regulator can decide when to, and when not to, provide such remuneration to investors. The remuneration is in reference to *other* businesses—not those under the regulator's control. Under this system of regulation, with us in the United States since 1944, the fact that some generation costs cannot now be recovered as competitive generation prices—but must be recovered as non-bypassable wires charges instead—has no bearing on what is due to utility investors. In other words, the presence of what we call "stranded costs" in this proceeding does not affect the regime under which investors can expect to be repaid for the use of their capital by ratepayers. The principles of compensation to investors based on opportunity cost still bind the Commission.

In terms of practicality, the Commission remains in the position of having to regulate electricity transmission and distribution—as well as gas distribution and other businesses. Even if the *Hope* decision did not continue to remain the standard to determine the compensation due to investors for the use of their capital in the public service, the Commission would have to consider the realities of capital markets. That is, the Commission must act in a way that allows investors to bank on the credibility of its commitments to safeguard the value of their capital. Investors have plenty of other options for their funds. Investors will only provide those funds at low cost to businesses regulated by the Commission if they know that the value of their capital investment will transcend periodic regulatory policy changes (like competition in generation or retail open access in gas).

Q. Has the issue of stranded cost recovery been dealt with in Pennsylvania?

A. Yes. The Act, consistent with the legal and practical principles I just discussed, states that stranded cost recovery will be allowed.

Q. If the Pennsylvania legislature has already passed a law requiring compensation for stranded costs, and if that law is not inconsistent with the *Hope* standard you mentioned earlier, then what are the remaining issues?

A. There are unresolved issues regarding the amount of stranded costs to be re-paid and the means by which they will be re-paid. For utilities like Duquesne to be treated fairly in this matter, it is important that the Commission has a very clear understanding of how these costs have arisen and why disallowances would create risks for the businesses that the Commission continues to regulate—risks that ultimately determine the cost to serve the public.

Q. Have investors already been fairly compensated for the risk of stranding, making any additional compensation at this point redundant?

A. No. There is no basis for arguing that ratepayers have already provided compensation to investors the very large stranded cost bills that face Duquesne in this proceeding (or many other electric utilities both in Pennsylvania and elsewhere). There are a couple of ways to see this—one regarding the principles that underlie utility regulation in the United States and one to do with how regulators have acted in the past.

Utility investors are not supposed to be speculators—nor are they compensated as such. That is, they do not engage in wagering—for a high return—on the prospect that their capital values will be maintained or will diminish through stranded cost disallowances. As I discussed at the outset of my testimony when discussing the *Bluefield* decision, the Supreme Court has ruled out such levels of compensation. Utility shareholders have no constitutional right to a level of compensation that would accompany speculative ventures.

Furthermore, commissions have indeed refused to give investors speculative rates of return when unusual conditions would dictate that such returns fairly compensate for the risk involved. There are a number of such examples. For example, in 1987, when Public Service of New Hampshire was having extraordinary troubles raising capital to continue to fund its operations, its commission refused to grant an equity rate of return that was even as high as the interest it was paying on its bonds (when the risk to equity holders at the time was obviously greater than for debt holders). Similarly, in 1992, when Transco, the interstate gas pipeline, faced severe financial difficulties, the Federal Energy Regulatory Commission rejected—with derision on the part of the Administrative Law Judge involved—reasonable evidence that its equity capital costs had reached speculative levels.[12]

Thus, from neither a principled nor a practical level have investors been able to expect to receive a return that would compensate for the large and unusual nature of stranded costs as identified in this proceeding before the Commission.

Q. If the risks of the stranded costs at issue in this proceeding are not the basis of the return traditionally granted for utilities, what kinds of risks have those returns covered?

A. Those returns cover the ordinary risks of investing in a regulated business where a number of factors (*e.g.*, operating, regulatory, financial, macroeconomic) contribute to less than perfect certainty about the ability to sustain stable dividend growths and share appreciations. Such risks have technical labels—*e.g.*, business risk and financial risk—but the practical manifestations of these risks are not hard to describe. Operating risk, for example, includes what happens when actual costs (or volumes sold) differ from those used to set the applicable rates. Regulatory risk, for example, includes regulatory lag, which traditionally has left investors exposed to inflation (with severe consequences in the late 1970s and early 1980s). Financial risk includes the swings in the fortunes of equity investors that arise when a certain portion of a utility's capital structure requires inflexible interest payments. Macroeconomic risks include all sorts of events in the economy that affect both the stocks of regulated and unregulated companies alike. These are only a few common examples of the risks that utility equity investors face.

All of this goes to say that without any mention of the possibility of stranded costs, the commensurate return due to utility equity investors covers many types of risks and uncertainties. It is true that these risks are lower for regulated business than for the average industrial business—but then the return granted is commensurately lower (particularly considering the greater level of financial risk—leverage—traditionally borne by utilities in order to lower overall capital costs for consumers).

[12] *Foster Natural Gas Report*, No. 1895, September 24, 1992, p. 6.

Q. Will these sources of risk for Duquesne change appreciably as a result of the CTC recovery plan?

A. No. The CTC is simply a means of collecting generating costs that Duquesne, under the old regulatory regime, would have collected through other means. The principal change is that a portion of Duquesne's generating costs will be recovered through an "unbundled" CTC rather than through bundled rates. Duquesne remains at risk that these unbundled rates will not be sufficient to earn the expected return.

Q. Is there any aspect of CTC recovery that materially reduces risk, such as the "nonbypassability" of the CTC?

A. It is my understanding that Duquesne is proposing a CTC that recovers stranded costs in two parts (i) a fixed customer charge, and (ii) a variable charge. The fixed customer charge is "nonbypassable" in the sense that it does not vary with usage levels. Thus, at best only a portion of CTC recovery is nonbypassable, assuming a customer continues to take service at its existing premise. A fixed customer charge is not a novel ratemaking device; rather, utility rates have traditionally included fixed customer charges. They also have included fixed demand charges that do not vary with aggregate electricity usage, but rather are levied on the basis of customer peak demands. These forms of rate design simply reflect the fact that certain costs, particularly "sunk" investments, do not vary with customer usage and therefore are more appropriately recovered through fixed charges. In any event, the fixed customer charge is not designed to recover the full amount of CTC, given that the remainder is to be recovered in a redesigned variable charge. On balance, it is my opinion that the fixed customer charge will have little or no effect on Duquesne's risk, particularly when other aspects of Duquesne's stranded cost recovery proposal are considered.

Q. Please explain your latter point.

A. Duquesne is committing to a minimum schedule of accelerated amortization and depreciation of regulatory assets and generation plant through the transition period. In doing so, Duquesne has accepted the risk that it cannot satisfy the commitment *and* earn its expected return if, for example, costs increase or sales volumes are lower than expected. This proposal places risk on Duquesne's shareholders that is greater than it would be under traditional regulation—where

Duquesne would normally retain the right to seek a rate increase should it not be earning its expected return.

Q. Isn't it true that utility returns often differ from their allowed return?

A. Yes. Owing to regulatory lag and a variety of factors, utilities frequently differ from the rate of return they have been awarded by their regulator. Seeing that the parameters that determine rates (like costs and volumes sold) must be determined in advance, this is to be expected.

Q. Are you familiar with the 1993 NARUC study which compared electric and telephone utility stockholder returns with returns on industrial stocks?

A. Yes.

Q. Why is this study relevant to the present case?

A. This study has been cited in similar proceedings before this Commission as evidence that electric utilities "have already been paid" for the risk of stranded assets in the form of excessively high returns and that therefore no additional compensation for stranded assets is now justified.

Q. What are the study's conclusions?

A. The main conclusions are as follows:

> The common stockholders of 72% of all major electric and telecommunication utility companies earned a higher internal rate of return on investment than did the average stockholder of the major non-regulated U.S. industrial corporations over the 21-year period 1972-1992. (page i)

> The study confirms that the often repeated arguments of utility sympathizers regarding the "inadequacy" of earnings and the inability of utilities to attract investment capital are unfounded and without merit. (page ii)

Q. Do you agree with these conclusions?

A. No. As I explain below, the study has serious flaws which lead the authors to dramatically overstate the returns earned by utility shareholders during the period of the study.

Q. Please describe the methodology of the study.

A. The authors looked at 21 years of data (1972-1992) for 97 utility companies (including both electric and telephone companies), the S&P 400, and the Value Line Industrial Composite.[13] Using stock sale prices and dividends the authors prepare an internal rate-of-return analysis which purports to show the return earned by the average investor. Capital gains and losses on the sale of stock are calculated by assuming the stock is held for "holding periods" of three years or more. The study analyzes returns for each stock for 171 separate holding periods—all of the possible periods from 1972 to 1992.

Q. What is the rationale for the use of "holding periods"?

A. The holding period analysis is apparently designed to mimic the way investors buy and sell stock. It is also a means of recognizing capital gains (or losses) from changes in the stock's price.

Q. Do you believe the NARUC study provides valid results?

A. No. There are two main problems with the study, both of which lead the study's authors to overstate the returns earned by utility investors. The first problem is that the holding period analysis overstates the importance of returns earned in years in the middle of the study period and understates the importance of returns earned toward the beginning and end of the period. This is simply because the years at either end of the study period are included in fewer of the sample holding periods than are the years in the middle of the study period. For example, the year 1972 is included in only 18 of the distributions, while the year 1981 is included in 114 distributions.

A related problem is that so far as I can tell the NARUC study's average internal rates of return are derived by straight averaging rather than weighted averaging. That is, in forming their final results the NARUC authors appear to have taken a simple average of their results for all 171 holding periods they studied, rather than accounting for the fact that the holding periods should be weighted proportionally to their duration. Simple averaging is an incorrect approach because, for example, it gives equal weight to returns earned over a 3 year holding period as to

[13] The study includes three separate methodologies for analyzing returns. I focus on the first methodology—the internal rate of return—because that is the part of the study which gives the most exaggerated results and which is consequently most commonly cited as evidence of utility overearnings.

returns earned over a 20 year holding period. If the return on a stock was 15% from 1972 to 1975 and 5% from 1972 to 1992, the NARUC methodology would produce a return of 10% for the stock—clearly a wrong result.

In sum, the NARUC study authors' use of holding period analysis leads them to overstate the returns earned by electric utilities for two reasons: (1) it systematically over-weights returns earned in the middle years of the study; and (2) electric utility returns were high during those middle years relative to other companies' stocks "due primarily to changes in economic conditions (namely declining inflation and interest rates in the 1980s) and not to excessively high authorized rates of return."[14]

Q. What is the second major problem with the NARUC study?

A. The second problem with the study is simply that because it was completed in 1993 it is out of date. As is well known, 1992 was a very important year for utility investors because of the Energy Policy Act. 1992 is generally recognized as the year that competitive electricity markets—and stranded utility investments—began to be incorporated in investor expectations. The stock prices of many investor owned electricity utilities began to drop as Wall Street analysts started incorporating stranded asset liabilities in company valuations.

Q. What did the NARUC study find regarding Duquesne's return?

A. Duquesne placed near the bottom in all three analyses. Duquesne's returns were lower than most other utilities and were also lower than the industrials.

- Method I ("Internal Rate of Return") ranked DQE 82 out of the 97 utilities included in the study. Duquesne's IRR (as calculated by NARUC) was 11.92% while utilities as a whole averaged 14.46% and the S&P 400 companies averaged 12.95%.

- Method II ("Basic Rate of Return") ranked DQE 85 out of the 97 utilities, with a basic rate of return of 8.69% as compared to the utility average of 11.14% and the S&P 400 average of 11.46%.

[14] For this second point see "A Critical Review and Analysis of the NARUC Report Entitled: Electric and Telephone Utility Shareholder Returns; 1972-1987" by Stephen G. Kihm, Wisconsin PSC; July 20, 1989.

- Method III ("Investor Wealth Approach") ranked DQE 79 out of the 97 utilities, with an *investor wealth* rate of return of 208.14% compared to the utility average of 305.10% and the S&P 400 average of 234.51%.

Q. Do you believe the NARUC analysis is valid?

A. No. For the reasons stated above, I believe the NARUC analysis does not provide useful information to the Commission regarding the level of earned returns. It overstates the returns earned by DQE shareholders in a very misleading way.

Q. Can you recommend an alternative to the NARUC "holding period" analysis?

A. Yes. I have prepared an alternative analysis which assumes a single holding period for each stock.[15] My methodology is very similar to that followed in the NARUC study except that I have eliminated the "holding period" analysis in order to avoid the weighting problems I described above. I also extended the study to the most recent year for which complete data are available (1996).

I have assumed the stock is purchased in the beginning year (1972) at the average price for the year and sold in the ending year (1996) at the average price. I assumed the investor received only one half of the dividends awarded in both the beginning and ending years and received all dividends in between.

Q. What are the results of your analysis?

A. My internal rate-of-return analysis reveals that for electric utilities the average internal rate of return from 1972 to 1992 was 9.51% while the return for the S&P Industrials was 10.20% and for the S&P Utilities was 10.99%. When I applied the same analysis to the period from 1972 to 1996, I found that the internal rate of return for electric utilities declined to 9.44%, while the internal rates of return for the S&P Industrials and the S&P Utilities grew to 10.49% and 11.19%, respectively. These results are in **Exhibit JDM - 14**.

[15] We have excluded Cincinnati Gas & Electric, Gulf States, Iowa Illinois Gas & Electric, Midwest Resources, PSI Resources and San Diego Gas & Electric used in the NARUC study because these companies have been involved in mergers after 1992 and they do not exist anymore.

Contrary to the assertions of the NARUC study authors, electric utility investments have consistently earned *less* than investments in both industrial stocks and utility stocks as a whole. Clearly there is no factual basis for the assertion that investors in electric utilities have been excessively rewarded for their investments and that these alleged excess earnings have compensated these investors for the risk of stranded costs.

Q. How has Duquesne fared in relation to other electric utility stocks?

A. Duquesne's total common stock returns (including dividends and capital appreciation) lagged behind both electric utilities and the S&P Utilities from 1972 to 1994 (when the performance of Duquesne's unregulated activities started to become noticed by the market). **Exhibit JDM - 15** charts the total returns for Duquesne and the other two indexes. From these data, over a period not typified by the prospect of competition in electricity in the U.S., Duquesne's equity investors fared worse than many other electric utilities (or utilities in general, as shown by the S&P Utilities group).

VII. CONCLUSION

Q. What is your final recommendation for Duquesne's rate of return on equity?

A. My final rate of return for Duquesne is **11.65 percent**, which is based on a DCF result for a proxy group of electric utilities.

Q. Does this conclude your direct testimony?

A. Yes.

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EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
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Graduate Study, 1980-1981

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M.A., Economics, 1980
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EMPLOYMENT

1996-present	Senior Vice President National Economic Research Associates, Inc., (NERA) Cambridge, Massachusetts.
1986-1996	Vice President/Senior Consultant National Economic Research Associates, Inc., (NERA) Cambridge, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist Associated Utility Services, Inc., Moorestown, New Jersey.

TESTIMONY

Before the State Corporation Commission of the State of Kansas, Prepared Direct Testimony on behalf of Kansas Pipeline Partnership, Docket No. 97-WSRG-312-PGA, May 23, 1997, in the matter of the Partial Suspension of Western Resources' Monthly Purchased Gas Adjustment (PGA) Effective Date December 1, 1996. Subject: Prudence examination of several gas commodity and gas transportation contracts.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of Consolidated Edison Company of New York, Inc., Owens Corning, PECO Energy Company, Philadelphia Gas Works, and Washington Gas Light Company, Docket No. RP95-197-71-001, March 24, 1997. Subject: Opposing the roll-in of incrementally priced pipeline gas transport capacity.

Before the Massachusetts Department of Public Utilities, Prepared Direct Testimony on behalf of Distrigas of Massachusetts Corporation, Docket No. D.P.U. 96-50, July 19, 1996. Subject: Retail unbundling of local distribution rates and recovery of stranded costs.

Before the Federal Energy Regulatory Commission, Prepared Cross-Answering Testimony on behalf of Consolidated Edison Company of New York, Inc., Owens-Corning Fiberglas Corporation, PECO Energy Company, Philadelphia Gas Works, and Washington Gas Light Company, Docket No. RP95-197-000, May 28, 1996. Subject: Opposing the roll-in of incrementally priced gas pipeline capacity.

Before the New Zealand Select Parliamentary Committee on Transportation, Comments on the Proposed Amendments to the Regulation of Airports in New Zealand (with Alfred E. Kahn), March 13, 1996. Subject: The oversight of airport authorities and conduct of airport pricing practices.

Before the Virginia State Corporation Commission, Prepared Rebuttal Testimony on behalf of Southwestern Virginia Gas Company, Case No. PUE950019, October 13, 1995. Subject: Fair rate of return.

Before The State Corporation Commission of the State of Kansas, Prepared Rebuttal Testimony on behalf of Kansas Pipeline Partnership, Docket No. 192,506-U, Docket No. 192,391-U, Docket No. 192,507-U, August 1, 1995. Subject: Competitive entry and pricing of new gas pipeline capacity.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission, Prepared Rebuttal Testimony on behalf of Valley Resources, Inc., Case No. 2276, June 15, 1995. Subject: Cost of capital

Before a private arbitration panel, in the Matter of Marathon Oil Company v. Southern California Gas Company, Expert Rebuttal Report, April 21, 1995. Subject: Capacity costs on major U.S. pipeline companies.

Before a private arbitration panel, in the Matter of Marathon Oil Company v. Southern California Gas Company, Expert Initial Report, April 7, 1995. Subject: The effect of U.S. interstate gas pipeline capacity on gas contract prices and delivery conditions.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission, Prepared Direct Testimony on behalf of Valley Resources, Inc., Case No. 2276, January 19, 1995. Subject: Cost of capital.

Before the Virginia State Corporation Commission, Prepared Direct Testimony on behalf of Virginia Electric and Power Company, Case No. PUE940052, January 17, 1995. Subject: Gas utility line extension policies.

TESTIMONY (Cont'd.)

Before the Virginia State Corporation Commission, Prepared Direct Testimony on behalf of Virginia Electric and Power Company, Case No. PUE940031, September 30, 1994. Subject: Gas utility line extension policies.

Before the Federal Energy Regulatory Commission, Comments of NERA, sponsored by Commonwealth Gas Company and Yankee Gas Services, Docket No. PL94-4-000, (with Louis Guth) September 26, 1994. Subject: Pricing interstate pipeline capacity expansions.

Before the Kansas Corporation Commission, Prepared Rebuttal Testimony Regarding the Fair Rate of Return on behalf of Kansas Pipeline Partnership and Kansas Natural Partnership, Docket No. 190,362-U, September 23, 1994. Subject: Cost of capital.

Before the Kansas Corporation Commission, Prepared Rebuttal Testimony on Market Entry Cost Recovery on behalf of Kansas Pipeline Partnership and Kansas Natural Partnership, Docket No. 190,362-U, September 23, 1994. Subject: Gas pipeline market power in firm delivery capacity and evaluation of the economic benefits of pipeline entry.

Before the California Public Utilities Commission, Amended Direct Testimony on behalf of Sierra Pacific Power Company, Application 94-05-009, July 1, 1994. Subject: Cost of capital.

Before the Federal Energy Regulatory Commission, Prepared Rebuttal Testimony on behalf of the New England Customer Group of 15 Natural Gas Distribution Companies, Docket No. RP91-203-000 (Tennessee Gas Pipeline Company), May 27, 1994. Subject: Gas pipeline rate design.

Before the Indiana Utility Regulatory Commission, Prepared Rebuttal Testimony on behalf of Northern Indiana Fuel and Light Company, May 9, 1994. Subject: Evaluation of gas supply framework for new gas storage services.

Before the California Public Utilities Commission, Prepared Direct Testimony on behalf of Sierra Pacific Power Company, May 6, 1994. Subject: Fair rate of return.

Before the Federal Energy Regulatory Commission, Prepared Cross-Answering Testimony on behalf of the New England Customer Group of 15 Natural Gas Distribution Companies, Docket No. RP91-203-000 (Tennessee Gas Pipeline Company), May 6, 1994. Subject: Interruptible transport rates and hourly take flexibility on interstate gas pipelines.

Before the Indiana Utility Regulatory Commission, Prepared Rebuttal Testimony on behalf of Northern Indiana Public Service Company, Cause No. 37306-GCA 39, March 30, 1994. Subject: Security of supply and methods for evaluating the appropriateness of gas storage investments.

Before the Federal Energy Regulatory Commission, Prepared Direct and Answering Testimony on behalf of the New England Customer Group of 15 Natural Gas Distribution Companies, Docket No. RP91-203-000 (Tennessee Gas Pipeline Company), February 14, 1994. Subject: Gas pipeline rate design.

Before the Federal Energy Regulatory Commission, Prepared Rebuttal Testimony on behalf of the Algonquin Customer Group of 14 Natural Gas Distribution Companies, Docket No. RP93-14-000 (Algonquin Gas Transmission Company), January 12, 1994. Subject: Assignment and sale of pipeline capacity under open access.

Before the Public Service Commission of the State of New York, Prepared Direct Testimony on behalf of the Brooklyn Union Gas Company, Case No. 93-G-0941, November 1, 1993. Subject: Fair rate of return.

TESTIMONY (Cont'd.)

Before the Commerce Commission of New Zealand, Testimony on behalf of Natural Gas Corporation, ISSN No. 0114-2720, October 27-29, 1993. Subject: Analysis of open-access gas tariffs and contract proposals.

Before the Federal Energy Regulatory Commission, Prepared Cross-Answering Testimony on Behalf of the Algonquin Customer Group of 14 Natural Gas Distribution Companies, Docket No. RP93-14-000 (Algonquin Gas Transmission Company), September 15, 1993. Subject: Assignment and sale of pipeline capacity under open access.

Before the Public Service Commission of the State of Wisconsin, Rebuttal Testimony on behalf of Wisconsin Gas Company, Docket No. 6650-GR-111, August 20, 1993. Subject: Fair rate of return.

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Before the Public Service Commission of the State of New York, Rebuttal Testimony on behalf of Jamaica Water Supply Company, Case No. 92-W-0583, May 28, 1993. Subject: Fair rate of return.

Before the Public Service Commission of the State of New York, Rebuttal Testimony in Support of Multi-Year Agreement on behalf of New York State Electric and Gas Corporation, Case No. 92-E-1084, et al., May 3, 1993. Subject: Reasonableness of a multi-year rate of return settlement.

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Before the State Corporation Commission of the State of Kansas, Prepared Rebuttal Testimony on behalf of Centel Corporation, Docket No. 175,456-U, October, 1991. Subject: Sale of electric utility investment.

Before the Public Service Commission of the State of New York, Prepared Direct Testimony on behalf of the New York State Electric and Gas Corporation, Case No. 91-E-0863, et al., August 28, 1991. Subject: Fair rate of return.

Before the Public Service Commission of the State of New York, Prepared Supplemental Testimony on behalf of The Brooklyn Union Gas Company, Case No. 90-G-0981, July 29, 1991. Subjects: Reasonableness of a multi-year rate of return settlement.

TESTIMONY (Cont'd.)

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Summary of Domestic Options and Issues
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PARTIAL LIST OF CLIENTS SERVED WORLDWIDE

ELECTRIC UTILITY

Alberta Power Limited
Atlantic Electric Company
Boston Edison Company
Central Hudson Gas and Electric
Commonwealth Edison Company
Commonwealth Energy System
Conowingo Power Company
Consolidated Edison Company
Duquesne Light Company
Green Mountain Power Company
Long Island Lighting Company
Nantahala Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power
Ohio Power Company
Orange & Rockland Utilities
Pennsylvania Power Company
Pennsylvania Power and Light Company
Philadelphia Electric Company
Portland General Electric Company
Public Service Company of New Hampshire
Public Service Company of New Mexico
Rochester Gas & Electric
Sierra Pacific Resources
Tampa Electric Company
Western Massachusetts Electric Co.
West Penn Power Company

GAS UTILITY

ARKLA, Inc.
Atlanta Gas Light Company
Bay State Gas Company
Berkshire Gas Company
Blackstone Gas Company
Boston Gas Company
Bristol & Warren Gas Company
British Gas plc
Brooklyn Union Gas Company
Canadian Western Natural Gas
Chattanooga Gas Company
Colonial Gas Company
Commonwealth Gas Company
Connecticut Natural Gas Corp.
Consolidated Gas Supply Corp.
Elizabethtown Gas Company
Empire State Pipeline Company
ENAGAS (Spain)
EnergyNorth, Inc.
Essex County Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas and Fuel Corporation of Victoria
Granite State Gas Transmission, Inc.
Great Falls Gas Company
Holyoke, Mass. Gas & Electric Dept.
ICG Utilities (Ontario) Ltd.
KN Energy, Inc.
Middleborough Municipal Gas & Electric
National Fuel Gas Distribution Corp.
Natural Gas Corporation of New Zealand
Natural Gas Pipeline of America
Norwich Department of Public Utilities
Pacific Gas Transmission
Pemex Gas y Petroquímica Básica
Pennsylvania Gas and Water Company
Peoples Gas Light and Coke Company
Providence Gas Company
Southern Connecticut Gas Company
Southwest Gas Corporation
Transwestern Pipeline Company
Valley Gas Company
Washington Gas Light Company
Westfield Gas & Electric Light Dept.
Wisconsin Gas Company
Yankee Gas Services Company

TELEPHONE UTILITY

Centel Corporation
Continental Telephone Company of Illinois
General Telephone of Pennsylvania
General Telephone Company of Ohio
Pacific Bell Telephone Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (Cont'd.)

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re: Delmarva Power & Light Company

District of Columbia Public Service Commission
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Air New Zealand
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General Electric Company
Intel Corporation
Jamaica Water Supply Company
Nucor Steel Corporation
Parsons Brinckerhoff Development Group

MEMBERSHIP IN PROFESSIONAL ORGANIZATIONS

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n/e/r/a topics

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Reporting NERA's work on public policy, management and litigation economics

RATE OF RETURN IN A MORE PROGRESSIVE REGULATORY RATE-SETTING PROCESS
or
CAN WE UNTIE THE GORDIAN KNOT?

By

*Jeff D. Makholm**
Vice President

. . . no one anywhere has yet devised a way to make the process of determining the fair return an agreeable one.

The continuing role of rate of return analysis is a very important issue, and no one anywhere has yet devised a way to make the process of determining the fair return an agreeable one. I will examine why the process seems so difficult and whether moving toward more progressive utility regulation (in the U.S. and elsewhere) has the potential to make it easier.

The perspective I offer on rate of return problems comes from my work with the subject in a variety of contexts: (1) estimating the fair rate of return for U.S. utilities in the context of traditional rate cases; (2) assisting non-U.S. utilities with rate of return issues within the context of different regulatory regimes abroad; and (3) helping foreign governments that are privatizing state-owned utilities, draft regulations that address both the periodic calculation of rate of return and utility price regulation generally.

These different contexts have forced me to consider rate of return problems from the following perspectives: (1) the "old" regulatory framework in the United States; (2) the "new" regulatory frameworks in places like the United Kingdom and Australia (price-cap regulation) and New Zealand (voluntary regulatory constraints); and (3) as a writer of new regulations that attempt to avoid the largest drawbacks I perceive in the existing regulatory frameworks.

With these perspectives in mind, I begin by discussing rate of return in the current ratemaking process in the United States. Then I will briefly describe the evolution of rate of return analysis, where it has come from and where it is now. Next I will discuss what options are available to curb the incessant fighting over rate of return. Finally I will present my concluding thoughts on the future of rate of return analysis.

* *Dr. Makholm is a Vice President of National Economic Research Associates, Inc. (NERA). This article is based on a speech to the National Society of Rate of Return Analysts annual forum in Philadelphia, Pennsylvania, on April 27, 1993.*

I. THE CURRENT STATE OF THE RATEMAKING PROCESS

The current ratemaking process is tortuous and unsatisfactory for commissions, utilities and ratepayers. A Mississippi Supreme Court Judge captured a quintessential aspect of the process when he said, "[u]tility rate litigation has become sport, a vent for passions. Each contest satiates for the moment, then fuels the appetite for further fight. We shrink from the thought of the season ending . . . .[1]"

This statement should ring uncomfortably true for all those closely connected to the regulatory process in the United States. It is not, however, the direct consequence of the actions of attorneys, consultants, intervenors, Commissioners or staff that creates this problem. It is the *regulatory process* that makes it almost inevitable that rate case issues are subject to repeated and increasingly detailed—and costly—inquiry. This regulatory framework not only provides questionable incentives for efficient operation for utilities, it also creates a process that operates at great cost. Both of these features (poor incentives and high cost) create an environment for contentiousness over the issue of rate of return.

A. Incentives for Efficiency

The current regulatory framework sets efficient utility behavior as its goal but always seems to fail to reach it. There are some valid reasons why.

It is the *regulatory process* that makes it almost inevitable that rate case issues are subject to repeated and increasingly detailed—and costly—inquiry.

First, the definition of efficiency is elusive. It is difficult for regulators, consultants, accountants, and sometimes *the company itself*, to distinguish between efficient and inefficient behavior. While measures of utility efficiency have been developed (e.g., labor productivity, total factor productivity, heat rates or equivalent availability, number of complaints, etc.), there will always be a large component of utility performance that falls outside of what can be objectively analyzed and measured.

This inability to effectively monitor performance means that hands-on regulators are doomed, like Odysseus, to steer a course between Scylla and Charybdis. By steering away

1 Justice Robertson, Mississippi Supreme Court, *State of Mississippi et al., v. Mississippi Public Service Commission and Mississippi Power Company*, January 4, 1989.

from the Scylla of the pure cost-plus contract, where ratepayers face runaway costs, regulators risk being drawn into Charybdis, the periodic and sometimes large disallowances that threaten utility financial integrity and ratepayer security.

Second, this failure to have objective standards for efficiency is compounded by "information" and/or "agency" problems. It is difficult for outsiders or those without years of experience to evaluate the decisions of utility managers (or to even know what those managers do). Utility managers are likely always to be more informed regarding the company they manage than regulators or their staffs. It is very difficult to monitor utility decisions when the information flow is so incomplete or when regulators must rely on utility managers to volunteer information on poor decisions.

. . . objective standards may never exist to confirm estimates of costs. In the case of rate of return, there is no way of knowing what the true fair rate of return is . . . even in hindsight.

Third, and most pertinent to rate of return, objective standards may never exist to confirm estimates of costs. In the case of rate of return, there is no way of knowing what the true fair rate of return is (or was), even in hindsight. All we ever have is forward-looking rate of return estimates and historical earned returns. This is not so for any other cost category. For example, estimates of depreciable lives can always be updated by experience with actual capital assets. The same is true with estimates of marginal cost—experience will tend to confirm better estimates in the future. But the "true" rate of return is always unverifiable.

B. Cost of the Process

The second major problem with the current ratemaking process is its cost. Not only does the process serve us poorly, it is exorbitantly expensive. The recent Generic Financing Proceeding in New York, initiated to review rate of return and financial policies, had a staggering price tag in professional fees and the loss of productive time for utility and Commission employees.

II. THE EVOLUTION OF RATE OF RETURN ANALYSIS

The fair rate of return began to be a hotly and repeatedly contested issue in the early 1970s when the electric utility business, in particular, was undergoing the "triple threat" of unprecedented inflation, rapid fuel price increases and the end of decades of impressive technical advances in lower-cost generating technology. The Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) methods got their start at this time and have survived nearly unchanged as the primary rate of return methods.

Improvements in the theoretical accuracy, objectivity, and reliability of these methods have come at a snail's pace and generally address only minor issues. For example, more than a dozen years ago, arguments raged in rate of return proceedings over whether to use forward-looking, rather than historical, information in the financial models used to calculate the rate of return.[2] Two years ago, the argument had progressed to smaller issues (in terms of the potential effect on rate of return) such as the ex-dividend date adjustments and the inclusion into the sustainable growth model of an allowance for the selling of stock at prices above book value.

. . . every seeming advance in rate of return analysis is followed by a retreat.

Meanwhile, every seeming advance in rate of return analysis is followed by a retreat. Historically-based "comparable earnings" analyses, presumed dead after the advent of the well grounded financial theories like DCF and CAPM, have risen like a Phoenix from the ashes of past regulation to be considered as a rate of return technique in some states. Furthermore, sound theoretical models are often sacrificed on the altar of *ad hoc* adjustments, when staff or company analysts scramble to move a model's results down or up for a never-ending variety of reasons that are impossible to verify empirically or theoretically.

It remains true today that most rate case issues, with the exception of major cost items, are capable of being settled in relatively short order *except* for rate of return, where the old issues are continually battled out. So, what are the options to reduce the scope of the interminable fighting over rate of return?

III. POSSIBLE OPTIONS TO REDUCE RATE OF RETURN CONFLICTS

There are two broad initiatives that may reduce the contention that surrounds rate of return analysis: (1) reduce the number of rate of return issues to fight about by simplifying the process or agreeing on specific techniques and data to use; or (2) use alternative regulatory

[2] In reality, this issue has—depressingly—never gone away entirely.

frameworks that either eliminate the need to set the fair rate of return or that lengthen the time between rate cases.

A. Narrow the Number of Rate of Return Issues

At times it seems that the goals of theoretical accuracy and usefulness are mutually exclusive attributes in rate of return models used in utility rate cases.

Rate of return techniques abound, but very little time and attention is paid to determining which have *practical* usefulness. The theories that underlie the empirical determination of the cost of capital (for which Nobel Prizes have been awarded) have become increasingly arcane and irrelevant to the practical ratemaking world, where common sense, believability and simplicity determine which techniques an administrative law judge or commissioner will use to set the allowed return. At times it seems that the goals of theoretical accuracy and usefulness are mutually exclusive attributes in rate of return models used in utility rate cases.

Although much time is spent discussing the technical aspects of rate of return techniques, we never get around to establishing criteria for determining *whether they are any good* in the world we face in real rate cases. The following table, as an example, compares the DCF, CAPM and Arbitrage Pricing Theory (APT) models along the following criteria: clarity, theoretical support, empirical objectivity, accuracy and stability.

ARE THE VARIOUS RATE OF RETURN METHODS USEFUL?

	DCF	CAPM	APT
Clarity	***	**	*
Theoretical Support	**	**	***
Empirical Objectivity	***	**	*
Accuracy	?	?	?
Stability	***	**	*

*** Good ** Fair * Poor ? Unknown

If staff, company, and ratepayer groups could establish consensus on the overall efficacy of rate of return techniques and on the definition of desirable attributes, such as in the example I present here, a consensus might also emerge on the types of data to use and *how* to use them. I am not sanguine, however, that this consensus will develop soon. The Federal Energy Regulatory Commission's generic rate of return process, begun in 1986, ended in a fog of adjustments for a seemingly endless procession of "special cases." The 1991-1993 Generic Financing Proceeding in New York, which was designed to produce an objective standard for setting the fair rate of return, has not proven that it can streamline the process. The methods adopted there, from my perspective, are overly complex, *ad hoc*, and will probably lead to further expensive fights and litigation when the financial winds shift. And with *both* generic proceedings, such great time, effort and expense was consumed attempting to establish generic rules in the first place, there was (and is) much "ground to make up" before the proceedings could (or can) be said to have been worthwhile in a larger context.

B. Using Alternative Regulatory Frameworks

There are at least four potential ways to reduce rate of return contention. *First*, unbundling and deregulation must be considered. The airline industry, trucking industry, gas production and electricity generation capacity are examples of industries that once fell under comprehensive rate of return regulation and were subsequently deregulated either partially or fully.

Unbundling and deregulation would reduce rate of return battles because they would reduce the size of the asset base subject to rate regulation. In other words, if the pie were smaller, there would be less incentive to fight. For example, in what I call the "*contractualization*" of the U.S. interstate gas transport industry, the determination of the fair rate of return should become increasingly less important as contractual obligations between gas transporters and distributors replace traditionally regulated rates. And if rate regulation ends completely (as in airlines), then the reason for the fight over rate of return vanishes.

. . . if the pie were smaller, there would be less incentive to fight.

A *second* way to shrink the size of the pie that is subject to regulation is to reduce the number of contested issues. Permitting cost pass-throughs like fuel adjustment clauses, weather adjustments, revenue decoupling mechanisms, and other techniques that remove attrition,[3] reduces the need for filing frequent rate cases because they eliminate factors that are outside of management's control.

Institutionalized price cap regulation is a *third* option. Price cap regulation, of the sort practiced in the United Kingdom, for example, allows prices to be indexed to both the general price level and to prices of significant inputs. As such, it has reduced the frequency of contested price-setting cases where rate of return is an issue. However, price cap regulation does not prevent rate of return from exploding as an issue when it *does* appear. For example, price cap regulation in the United Kingdom has not proven capable of eliminating a lengthy storm of contention over rate of return when the relatively infrequent rate cases *do* arise. Indeed, some of the price cap experience in the United Kingdom demonstrates the irony that rate of return inquiries may even be worse for their infrequency.[4]

Fourth, some jurisdictions increasingly are using multi-year settlements to lengthen the time between rate cases. Recently, New York State has shown some of the most progressive ratemaking in the country—although mostly behind the scenes. Two years ago, Brooklyn Union Gas settled a three-year stayout that included weather clauses, automatic adjustments, revenue decoupling mechanisms, sliding scale allowed return, and pre-approved financing. Other multi-year settlements have followed.

When I contribute to drafting utility regulations abroad (for instance, in Argentina, Bolivia and Chile), I try to specify stringent limits on the frequency of rate cases and on the ability of the cases to last longer than, say, 90 days. If the case is not settled in that amount of time, rates go into effect *not subject to refund*. Limiting the growth of the industry of *regulatory rate analysis* (on either the government or industry side) seems to be one of the best

[3] Attrition occurs when earnings are depressed over time because the marginal cost of new plant and equipment exceeds average costs and average prices.

[4] The investigation into fair rate of return in the U.K. water industry took months and involved hundreds of pages of written submission by the various parties involved. The subject of the fair rate of return in the gas industry in the U.K. has also received many months of inquiry with large written submissions by British Gas, the Ofgas (the regulator), and the Monopolies and Mergers Commission. In both cases, the scale of inquiry into rate of return issues was far greater than that afforded even the largest public utilities in the U.S., providing effective refutation, at least to me, of the potential for price cap regulatory regimes, *per se*, to alleviate contention over the issue.

ways to prevent fights over subjects like rate of return from growing.

IV. CONCLUDING THOUGHTS

My assessment of the potential for change is not very optimistic, and I have reached the following conclusions on the future of rate of return analysis in traditional utility industries like gas, electricity and water distribution. *First*, contention over the fair rate of return is an *unavoidable* component of utility regulatory oversight even under alternative frameworks. Efforts to make the process objective and mechanical are probably futile as an administrative and political matter. *Second*, the only realistic way to reduce rate of return contention over the long term is to deregulate or "contractualize" utility functions (like gas and electricity transmission), lengthen the time between rate cases by instituting price cap or other progressive regulatory programs, and strictly limit the time within which the rate of return issue must be resolved.

In other words, the "Gordian knot," depicting the complex and repeating struggle over the fair rate of return, remains tightly tied, and no individual, regulatory body or new regulatory structure appears capable of untying it as a practical matter. Rate of return analysis will remain an industry of its own tied to the business of regulatory price setting. However, there are ways to cut through the knot and fight the inevitable fight less often. These are deregulation, contractualization and less frequent rate setting.

. . . the "Gordian knot," depicting the complex and repeating struggle over the fair rate of return, remains tightly tied, and no individual, regulatory body or new regulatory structure appears capable of untying it as a practical matter.

DUQUESNE LIGHT COMPANY

THE DERIVATION OF THE DCF MODEL

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962 (*The Investment, Financing and Valuation of the Corporation*, published by Irwin). In his original version, the "Gordon" model was:

$$P_0 = \frac{D_0}{k_e - g}$$

where:

$$P_0 = \text{price of stock} \qquad \textbf{(2.1)}$$

D_0 = last dividend

k_e = cost of equity

g = growth rate of dividends

Professor Gordon derived his model assuming *continuous* compounding of dividends, using integral calculus. The "continuous" version of the DCF model is thus:

"Continuous" DCF Model

$$k_e = \frac{D_0}{P_0} + g \qquad \textbf{(2.2)}$$

Since dividends are not normally received continuously and, therefore, cannot be continuously reinvested by the investor, subsequent writers (including Gordon himself) modified this initial approach to reflect annual dividend payments. The resulting modification is known as the "periodic" DCF model.

Since all DCF models relate the current price of a stock to an expected *stream* of future dividend payments, the basic "periodic" DCF model starts with the equation:

$$P_0 = \frac{D_1}{(1+k_e)} + \frac{D_2}{(1+k_e)^2} + \ldots + \frac{D_n}{(1+k_e)^n} + \ldots$$

where:

$$P_0 = \text{current stock price} \qquad \textbf{(2.3)}$$

$$D_1, \ldots, D_n = \text{last dividend}$$

If dividends are assumed to grow at a constant growth rate, g, we can rewrite equation (2.3) as:

$$P_0 = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \ldots + \frac{D_0(1+g)^n}{(1+k_e)^n} + \ldots$$

where:

$$D_0(1+g) = D_1 \qquad \textbf{(2.4)}$$

$$D_0 = \text{last dividend payment}$$

Equation (2.4) can be solved for k_e to obtain:

$$k_e = \frac{D_0(1+g)}{P_0} + g. \qquad \textbf{(2.5)}$$

This is the familiar equation for the DCF cost of equity, which is the model most commonly used in regulatory proceedings. The model assumes annual dividend payments and a constant annual growth rate. However, if dividends are paid quarterly, rather than annually, equation (2.5) can understate the return that equity investors require. Because of the time value of money, annual and quarterly dividend payments are not perfect substitutes. Therefore:

$$P_0 = D_{04}\frac{(1+g)^{.25}}{(1+k_e)^{.25}} + D_{04}\frac{(1+g)^{.50}}{(1+k_e)^{.50}} + D_{04}\frac{(1+g)^{.75}}{(1+k_e)^{.75}} + \ldots$$

where:

D_{04} = last quarterly dividend payment **(2.6)**

This DCF model would be an acceptable quarterly model except for the assumption that dividend payments grow each quarter. A variant of equation (2.6) which allows the quarterly dividends to increase, if at all, only once a year is shown in equation (2.7).

$$\begin{aligned} P_0 = {} & \frac{D_{01}(1+g)}{(1+k_e)^{.25}} + \frac{D_{02}(1+g)}{(1+k_e)^{.5}} + \frac{D_{03}(1+g)}{(1+k_e)^{.75}} + \frac{D_{04}(1+g)}{(1+k_e)^{1.00}} + \\ & \frac{D_{01}(1+g)^2}{(1+k_e)^{1.25}} + \frac{D_{02}(1+g)^2}{(1+k_e)^{1.5}} + \frac{D_{03}(1+g)^2}{(1+k_e)^{1.75}} + \frac{D_{04}(1+g)^2}{(1+k_e)^{2.00}} + \\ & \frac{D_{01}(1+g)^3}{(1+k_e)^{2.25}} + \frac{D_{02}(1+g)^3}{(1+k_e)^{2.5}} + \ldots \end{aligned} \qquad \textbf{(2.7)}$$

where:

$D_{01}, \ldots, D_{04}$ = last four previous quarterly dividend payments.

This model is a more accurate extension of equation (2.6). The DCF formula presented as equation (2.7) can be reduced to:

$$k_e = \frac{D_{01}(1+k_e)^{.75} + D_{02}(1+k_e)^{.5} + D_{03}(1+k_e)^{.25} + D_{04}}{P_0}(1+g) + g \qquad \textbf{(2.8)}$$

In this model, the last four dividend payments may be specified explicitly. It is also assumed that each of the dividend payments is reinvested to years' end at the cost of equity. The model is, therefore, attractive for the purpose of calculating the cost of equity capital for firms which pay dividends quarterly.

The quarterly model, however, is not the correct model to apply to a utility's rate base. This is because quarterly dividend payments, like bank interest compoundings, allow a higher effective annual rate to be paid than the nominal rate applied to the principal amount.

Because equity investors, with an opportunity cost equal to the effective annual cost of capital, may be presumed to be able to reinvest quarterly dividends at that same rate, the dividend reinvestment portion of the effective annual cost of equity shown in (2.8) is:

$$\frac{D_{01}[(1+k_e)^{.75} - 1] + D_{02}[(1+k_e)^{.5} - 1] + D_{03}[(1+k_e)^{.25} - 1]}{P_0}(1 + g) \qquad \textbf{(2.9)}$$

Subtracting the return due to reinvestment from (2.8) leaves:

$$k_{e(nominal)} = k_{e(quarterly)} - \frac{D_{01}[(1+k_e)^{.75} - 1] - D_{02}[(1+k_e)^{.50} - 1] + D_{03}(1+k_e)^{.25} - 1]}{P_0}(1 + g)$$

$$= \frac{D_1}{P_0} + g$$

where:

$$D_1 = D_0(1+g) \qquad \textbf{(2.10)}$$

$$= [D_{01} + D_{02} + D_{03} + D_{04}](1+g)$$

Therefore, the return to apply to rate base with quarterly dividend payments is equal to the annual form of the DCF model.

Duquesne Light Company
Comparable Group Criteria

Company	Total Capitalization	Revenue from Electricity
	---($ Million)---	---(Percent)---
	(a)	(b)
Carolina Power & Light Co.	$ 5,359.9	100 %
Central and South West Corp.	8,151.0	99
Cinergy Corp.	5,313.7	85
DTE Energy Co.	7,483.3	99
Eastern Utilities Associates	812.1	89
Empire District Electric Co.	465.5	99
GPU, Inc.	6,741.7	100
Green Mountain Power Corp.	234.8	100
Idaho Power Co.	1,540.1	100
KU Energy Corp.	1,231.9	100
Minnesota Power & Light Co.	1,411.8	86
Nevada Power Co.	1,682.8	100
OGE Energy Corp.	1,840.3	87
PECO Energy Co.	9,308.5	90
PP&L Resources, Inc.	6,179.0	100 [1]
St. Joseph Light & Power Co.	159.3	87
United Illuminating Co.	1,271.4	100
Average	$ 3,481.6	95.4 %

[1] Based on 1994 data.

Source: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.

DUQUESNE LIGHT COMPANY

SELECTION OF THE PROXY GROUP

The initial pool of electric utilities used to select a proxy group consisted of 92 electric utilities as reported in the *Value Line Investment Survey*:

Allegheny Power System, Inc.
American Electric Power Co., Inc.
Atlantic Energy, Inc.
Baltimore Gas & Electric Co.
Black Hills Corp.
Boston Edison Co.
Carolina Power & Light Co.
Central Hudson Gas & Electric Corp.
Centerior Energy Corp.
Central and South West Corp.
Central Louisiana Electric Co., Inc.
Central Maine Power Co.
Central Vermont Public Service Corp.
CILCORP Inc.
Cinergy Corp.
CIPSCO, Inc.
CMS Energy Corp.
Commonwealth Energy System
Consolidated Edison Co.
Delmarva Power & Light Co.
Dominion Resources, Inc.
DPL Inc.
DTE Energy Co.
Duke Power Co.
DQE
Eastern Utilities Associates
Edison International
Empire District Electric Co.
Enova Corp.
Entergy Corp.
Florida Progress Corp.
FPL Group, Inc.
GPU, Inc.
Green Mountain Power Corp.
Hawaiian Electric Industries, Inc.
Houston Industries Inc.
Idaho Power Co.
IES Industries
Illinova Corp.
Interstate Power Co.
IPALCO Enterprises, Inc.
Kansas City Power & Light Co.
KU Energy Corp.
LG&E Energy Corp.
Long Island Lighting Co.
MDU Resources Group, Inc.
MidAmerican Energy Holdings Co.
Minnesota Power & Light Co.
Montana Power Co.
Nevada Power Co.
New England Electric System
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
NIPSCO Industries, Inc.
Northeast Utilities
Northern States Power Co.
Northwestern Public Service Co.
OGE Energy Corp.
Ohio Edison Co.
Orange & Rockland Utilities, Inc.
Otter Tail Power Co.
PacifiCorp
PECO Energy Co.
PG&E Corp.
Pinnacle West Capital Corp.
Portland General Corp.
Potomac Electric Power Co.
PP&L Resources, Inc.
Public Service Co. of New Mexico
Public Service of Colorado
Public Service Enterprise Group, Inc.
Puget Sound Energy, Inc.
Rochester Gas & Electric Corp.
SCANA Corp.

Sierra Pacific Resources
SIGCORP, Inc.
Southern Company
Southwestern Public Service Co.
St. Joseph Light & Power Co.
TECO Energy, Inc.
Texas Utilities Co.
TNP Enterprises Inc.
Tucson Electric Power Co.
Unicom Corp.
Union Electric Co.
United Illuminating Co.
UtiliCorp United Inc.
Washington Water Power Co.
Western Resources, Inc.
Wisconsin Energy Corp.
WPL Holdings, Inc.
WPS Resources Corp.

From this collection, those utilities that met the following criteria were included in the proxy group: 1) at least 85 percent of total operating revenue from electricity operations, 2) total capitalization less than $10 billion, 3) not involved in a (possible or recently completed) take-over, and 4) dividend stability and company solvency (EPS growth of less than 15 percent).

First, if a company's operating revenues from electricity were less than 85 percent of its total revenues the company was eliminated. Those companies eliminated under this criterion include:

Baltimore Gas & Electric Co.
Black Hills Corp.
Central Hudson Gas & Electric Corp.
CILCORP Inc.
CIPSCO, Inc.
CMS Energy Corp.
Commonwealth Energy System
Consolidated Edison Co.
DPL Inc.
Enova Corp.
Florida Progress Corp.
Hawaiian Electric Industries, Inc.
IES Industries
Illinova Corp.
LG&E Energy Corp.
Long Island Lighting Co.
MDU Resources Group, Inc.
MidAmerican Energy Holdings Co.
Montana Power Co.
NIPSCO Industries, Inc.
Northern States Power Co.
Northwestern Public Service Co.
Orange & Rockland Utilities, Inc.
Otter Tail Power Co.
PacifiCorp
PG&E Corp.
Public Service Co. of New Mexico
Public Service Enterprise Group, Inc.
Public Service of Colorado
Puget Sound Energy, Inc.
Rochester Gas & Electric Corp.
SCANA Corp.
Sierra Pacific Resources
SIGCORP, Inc.
UtiliCorp United Inc.
Washington Water Power Co.
Western Resources, Inc.
Wisconsin Energy Corp.
WPL Holdings, Inc.
WPS Resources Corp.

Second, if a company's total capitalization was greater than $10 billion, it was eliminated from the proxy group. This criterion is targeted at selecting a proxy group of an average size similar to Duquesne. Those eliminated include:

Dominion Resources, Inc.
Edison International
Entergy Corp.
Southern Company
Texas Utilities Co.
Unicom Corp.

Third, those companies which were currently or had recently been involved in merger activity were eliminated from the proxy group. Those eliminated include:

Allegheny Power System
American Electric Power Co., Inc.
Atlantic Energy, Inc.
Centerior Energy Corp.
Central Louisiana Electric Co., Inc.
Delmarva Power & Light Co.
Duke Power Co.
DQE
Houston Industries Inc.
Interstate Power Co.
Kansas City Power & Light Co.
Ohio Edison Co.
Portland General Corp.
Potomac Electric Power Co.
Southwestern Public Service Co.
TECO Energy, Inc.
Union Electric Co.

Fourth, stability in dividend payments and company solvency is required for inclusion in the proxy group. To determine this, I examined the *Value Line* company summaries as well as *Value Line*'s dividend and earnings per share growth estimates for the remaining companies. The following companies were excluded from the proxy group:

Boston Edison Co.
Central Maine Power Co.
Central Vermont Public Service Corp.
FPL Group, Inc.
IPALCO Enterprises, Inc.
New England Electric System
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
Northeast Utilities
Pinnacle West Capital Corp.
TNP Enterprises Inc.
Tucson Electric Power Co.

After all those companies were eliminated, the following 17 companies remain in the proxy group:

Carolina Power & Light Co.
Central and South West Corp.
Cinergy Corp.
KU Energy Corp.
Minnesota Power & Light Co.
Nevada Power Co.

DTE Energy Co.
Eastern Utilities Associates
Empire District Electric Co.
GPU, Inc.
Green Mountain Power Corp.
Idaho Power Co.
OGE Energy Corp.
PECO Energy Co.
PP&L Resources, Inc.
St. Joseph Light & Power Co.
United Illuminating Co.

Duquesne Light Company
Comparison of Spot - Date Adjusted Stock Price and Average Adjusted Stock Price for Comparable Group of Companies

Company	Next Ex-Dividend Date [1]	Stock Price Date [2]	Number of Days to Next Ex-Date [3]	Percent of Days Expired	Last Dividend Paid	Adjusted Dividend	Closing Stock Price	Spot-Date Adjusted Price	Average Adjusted Price
				---(Percent)--	--------	--------	----(Dollars)----	--------	--------
			[(a)-(b)]	[(90-(c))/90]		[(d)*(e)]		[(g)-(f)]	[(g)-(e)/2]
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Carolina Power & Light Co.	01-Oct-97	17-Jul-97	76	15.56	$ 0.47	$ 0.07	$ 35.38	$ 35.30	$ 35.14
Central and South West Corp.	04-Aug-97	17-Jul-97	18	80.00	0.44	0.35	21.75	21.40	21.53
Cinergy Corp.	27-Jul-97	17-Jul-97	10	88.89	0.45	0.40	33.75	33.35	33.53
DTE Energy Co.	15-Sep-97	17-Jul-97	60	33.33	0.52	0.17	29.50	29.33	29.24
Eastern Utilities Associates	25-Jul-97	17-Jul-97	8	91.11	0.42	0.38	19.38	19.00	19.17
Empire District Electric Co.	26-Aug-97	17-Jul-97	40	55.56	0.32	0.18	17.06	16.88	16.90
GPU, Inc.	21-Sep-97	17-Jul-97	66	26.67	0.49	0.13	35.88	35.75	35.63
Green Mountain Power Corp.	12-Sep-97	17-Jul-97	57	36.67	0.53	0.19	23.88	23.68	23.61
Idaho Power Co.	19-Jul-97	17-Jul-97	2	97.78	0.47	0.45	32.44	31.98	32.21
KU Energy Corp.	19-Aug-97	17-Jul-97	33	63.33	0.44	0.28	34.25	33.97	34.03
Minnesota Power & Light Co.	11-Aug-97	17-Jul-97	25	72.22	0.51	0.37	31.63	31.26	31.37
Nevada Power Co.	07-Oct-97	17-Jul-97	82	8.89	0.40	0.04	21.69	21.65	21.49
OGE Energy Corp.	06-Oct-97	17-Jul-97	81	10.00	0.67	0.07	45.69	45.62	45.36
PECO Energy Co.	21-Aug-97	17-Jul-97	35	61.11	0.45	0.28	22.38	22.10	22.15
PP&L Resources, Inc.	08-Sep-97	17-Jul-97	53	41.11	0.42	0.17	20.31	20.14	20.10
St. Joseph Light & Power Co.	29-Jul-97	17-Jul-97	12	86.67	0.24	0.21	16.63	16.42	16.51
United Illuminating Co.	03-Sep-97	17-Jul-97	48	46.67	0.72	0.34	34.06	33.73	33.70
								$ 27.739	$ 27.745

[1] The date the stock goes ex-dividend.
[2] Represents number of days in the quarter until the next ex-dividend date.
[3] Closing stock price for July 16, 1997 as listed in *The Wall Street Journal*, July 17, 1997.

Sources: *The Value Line, Investment Survey,* Edition 1, June 13; 1997, Edition 5, April 11, 1997 and Edition 11, May 23, 1997.
The Wall Street Journal, July 17, 1997.

Duquesne Light Company
Average Adjusted Stock Price
Comparable Group of Companies

Company	Average Stock Price [1]	Last Dividend Paid	Average Adjusted Price
	(Dollars)		
			[(a)-(b)/2]
	(a)	(b)	(c)
Carolina Power & Light Co.	$ 35.82	$ 0.47	$ 35.58
Central and South West Corp.	24.20	0.44	23.99
Cinergy Corp.	33.13	0.45	32.90
DTE Energy Co.	29.29	0.52	29.03
Eastern Utilities Associates	17.59	0.42	17.38
Empire District Electric Co.	18.11	0.32	17.95
GPU, Inc.	33.40	0.49	33.16
Green Mountain Power Corp.	24.00	0.53	23.74
Idaho Power Co.	31.00	0.47	30.77
KU Energy Corp.	30.59	0.44	30.37
Minnesota Power & Light Co.	28.17	0.51	27.92
Nevada Power Co.	20.51	0.40	20.31
OGE Energy Corp.	41.63	0.67	41.30
PECO Energy Co.	22.92	0.45	22.70
PP&L Resources, Inc.	21.86	0.42	21.65
St. Joseph Light & Power Co.	15.82	0.24	15.70
United Illuminating Co.	31.28	0.72	30.92
			$ 26.79

[1] Average of weekly (Friday) close prices from July 19, 1996 to July 18, 1997.

Sources: *The Value Line Investment Survey,* Edition 1, June 13, 1997; Edition 5, April 11, 1997 and Edition 11, May 23, 1997.
Factset Security Price History Report.

Duquesne Light Company
Annual DCF, Comparable Group of Companies

Company	Dividends Paid Q2 '96	Q3 '96	Q4 '96	Q1 '97	Dividend Sum (D_0)	Average Adjusted Price (P_0)[1]	B*R+S*V Growth[2]	EPS Growth Estimate[3]	Average Growth (g)	DCF Cost of Equity[4]
	---------	---------	---------	(Dollars)	---------	---------	---------	(Percent)	---------	---------
					[(a)+(b)+(c)+(d)]					
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Carolina Power & Light Co.	$ 0.46	$ 0.46	$ 0.47	$ 0.47	$ 1.85	$ 35.58	2.61 %	3.11 %	2.86 %	8.49 %
Central and South West Corp.	0.44	0.44	0.44	0.44	1.74	23.99	3.28	6.94	5.11	13.13
Cinergy Corp.	0.43	0.43	0.45	0.45	1.76	32.90	6.23	5.72	5.98	11.94
DTE Energy Co.	0.52	0.52	0.52	0.52	2.06	29.03	3.74	8.82	6.28	14.22
Eastern Utilities Associates	0.42	0.42	0.42	0.42	1.66	17.38	1.67	4.84	3.26	13.64
Empire District Electric Co.	0.32	0.32	0.32	0.32	1.28	17.95	5.82	6.69	6.25	14.23
GPU, Inc.	0.49	0.49	0.49	0.49	1.94	33.16	5.43	8.71	7.07	13.66
Green Mountain Power Corp.	0.53	0.53	0.53	0.53	2.12	23.74	4.67	2.81	3.74	13.49
Idaho Power Co.	0.47	0.47	0.47	0.47	1.86	30.77	3.81	2.08	2.95	9.50
KU Energy Corp.	0.43	0.43	0.43	0.44	1.73	30.37	2.82	2.87	2.85	9.01
Minnesota Power & Light Co.	0.51	0.51	0.51	0.51	2.04	27.92	2.92	3.82	3.37	11.32
Nevada Power Co.	0.40	0.40	0.40	0.40	1.60	20.31	3.78	3.47	3.63	12.22
OGE Energy Corp.	0.67	0.67	0.67	0.67	2.66	41.30	3.35	1.49	2.42	9.36
PECO Energy Co.	0.44	0.44	0.45	0.45	1.77	22.70	3.40	2.63	3.01	11.47
PP&L Resources, Inc.	0.42	0.42	0.42	0.42	1.67	21.65	2.87	0.48	1.68	9.94
St. Joseph Light & Power Co.	0.24	0.24	0.24	0.24	0.95	15.70	0.46	4.56	2.51	9.01
United Illuminating Co.	0.72	0.72	0.72	0.72	2.88	30.92	2.14	4.27	3.21	13.33
	$ 0.46	$ 0.46	$ 0.47	$ 0.47	$ 1.86	$ 26.79	3.47 %	4.31 %	3.89 %	11.65 %

[1] Equals the June 16, 1997 closing stock price adjusted for the ex-dividend date.
[2] B*R+S*V uses a five year average of S, multiplied by current V.
[3] Calculated using 1996 and five year projected data.
[4] Annual DCF equals $[D_o*(1+g)/P_o/(1-5.00\%)+g]$.

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
The Value Line, Investment Survey, Edition 1, June 13; 1997, Edition 5, April 11, 1997 and Edition 11, May 23, 1997.
Factset Security Price History Report.

DUQUESNE LIGHT COMPANY

DERIVATION OF SUSTAINABLE GROWTH WITH EXTERNAL STOCK FINANCING

The sustainable growth formula is:

$$g = B * R$$

where:

B = the expected retention rate (7.1)

R = the rate of return expected to be earned on common equity.

An assumption of the standard DCF model is that only one source of equity financing occurs, specifically the retention of earnings. That is, current dividends, D, are set at a constant percentage of normalized earnings, where normalized earnings are the expected rate of return on equity, R, applied to the current book value, V. Therefore, the sustainable growth formula is:

$$B = 1 - \frac{D}{(R_{av} * V)} \qquad (7.1)$$

and the long-run sustainable growth rate is:

$$g = B * R_{av}$$

$$= \left(1 - \frac{D}{(R_{av} * V)}\right) * R_{av} \qquad (7.2)$$

$$= R_{av} - \frac{D}{V}$$

where:

D = dividends declared per share, 2000-02 estimate

V = year-end book value per share, 2000-02 estimate

R_{av} = return on average equity.

However, the issuance and sale of new common equity can also increase earnings and dividends. Thus, the growth rate must be expanded to allow for continuous new equity financing. In the expanded formula, two activities are recognized: (1) investment decisions that earn the rate of R_{av}, and (2) stock financing operations which earn the rate $S*V$.

The sustainable growth would then be:

$$g = B * R_{av} + S * V \tag{7.3}$$

where:

B = the fraction of earnings to be expected to be retained

R_{av}= the expected return on average equity

S = funds raised from the sale of stock as a fraction of existing common equity

V = the fraction of funds raised from the sale of stock that accrues to shareholders at the start of the period.

The $S*V$ term is a measure of the impact on growth of the sale of stock at prices above or below book value. If stocks are sold at a price which exceeds book value, a portion of the funds goes to shareholders, whereas, if stocks are sold at a price less than book value, stockholders' equity will be diluted. For instance, given a market-to-book ratio of 1.3, abstracting from market pressure and selling costs, 23 percent of the funds raised in the issuance (1 - 1/1.3) go to increasing the value of stockholders' pre-existing shares (V = 0.23). If the new issuance is equal to 10 percent of the existing equity (S = 0.1), then $S*V$ = 0.023, meaning that ignoring the $S*V$ term in such a circumstance would understate k_e (cost of equity) by 2.3 percent.

Note: The expanded growth rate (and hence, the expanded DCF formula) will reduce to the standard version either when: (1) the company does not regularly sell new stock, S = 0, or (2) the new stock is sold at a price that equals book value, V = 0.

In calculating the sustainable growth rate, g, in this testimony, the S and V terms were calculated for the comparable group of companies as follows:

$$V = 1 - \left(\frac{BVPS}{P_{stock}} \right) \tag{7.4}$$

where:

P_{stock} = closing stock price

$BVPS$ = 1995 year-end book value per share

and,

$$S = \frac{Issuance_t}{CEQ_{t-1}} \tag{7.5}$$

where:

$Issuance_t$ = net proceeds the issuance of common stock in time period, t

CEQ_{t-1} = total common equity in previous time period, t-1

An average S from 1992-1996 was multiplied by V. This product was then added to $B*R$ to yield g, the sustainable growth rate.

Note: See Roger A. Morin, *Utilities' Cost of Capital*, (Arlington, Virginia: Public Utilties Reports, Inc., 1984), 99-102, for a full discussion of the DCF model considering external financing.

Data from *Utility Compustat II*, Standard & Poor's Compustat Services, Inc. was used for the calculation of S and V.

Duquesne Light Company
Sustainable Growth, Comparable Group of Companies

Company	R Estimated Return on Common Equity [1]	D_e Estimated Dividend [2]	V_e Estimated Book Equity [2]	V Book Equity Per Share 1996	V Book Equity Per Share 1995	R_{av} Return on Average Equity [3]	B [4]	B*R [5]	Average S*V [6]	B*R+S*V
	----(Percent)----	(Dollars)				(Percent)				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Carolina Power & Light Co.	13.0 %	$ 2.14	$ 22.20	$ 17.77	$ 16.93	13.32 %	27.60 %	3.68 %	-1.06 %	2.61 %
Central and South West Corp.	10.5	1.74	19.75	17.98	16.48	10.96	19.59	2.15	1.13	3.28
Cinergy Corp.	13.5	1.98	20.75	16.39	16.17	13.59	29.80	4.05	2.18	6.23
DTE Energy Co.	11.5	2.10	27.25	23.69	23.62	11.52	33.09	3.81	-0.07	3.74
Eastern Utilities Associates	10.0	1.55	19.20	18.19	18.36	9.95	18.90	1.88	-0.21	1.67
Empire District Electric Co.	12.5	1.28	14.85	12.96	12.69	12.63	31.76	4.01	1.81	5.82
GPU, Inc.	11.5	2.20	32.50	25.27	24.70	11.63	41.80	4.86	0.57	5.43
Green Mountain Power Corp.	10.0	1.48	25.95	22.22	22.01	10.05	43.23	4.34	0.32	4.67
Idaho Power Co.	11.5	1.90	21.00	18.47	18.15	11.60	21.99	2.55	1.26	3.81
KU Energy Corp.	12.5	1.92	19.50	17.07	16.62	12.67	22.26	2.82	0.00	2.82
Minnesota Power & Light Co.	11.5	2.10	21.75	18.65	18.56	11.53	16.24	1.87	1.05	2.92
Nevada Power Co.	10.5	1.60	17.65	16.40	16.25	10.55	14.06	1.48	2.30	3.78
OGE Energy Corp.	13.0	2.70	27.50	23.81	23.22	13.16	25.42	3.35	0.00	3.35
PECO Energy Co.	11.0	1.84	23.70	20.87	20.39	11.13	30.23	3.36	0.04	3.40
PP&L Resources, Inc.	11.0	1.67	19.00	16.88	16.29	11.19	21.47	2.40	0.47	2.87
St. Joseph Light & Power Co.	12.5	1.10	13.30	10.87	20.84	8.57	3.51	0.30	0.16	0.46
United Illuminating Co.	11.0	2.88	32.50	31.20	31.20	11.00	19.44	2.14	0.00	2.14
	11.6 %	$ 1.89	$ 22.26	$ 19.33	$ 19.56	11.47 %	24.73 %	2.89 %	0.59 %	3.47 %

[1] 2000-20002 estimate.
[2] 2000-2002 estimated per share dividends and book value.
[3] $R_{av}=(2*R*V_{96})/(V_{96}+V_{95})$.
[4] $B=1-(D_e/(R_{av}*V_e))$.
[5] $B*R=B*R_{av}=(R_{av}-D_e/V_e)$.
[6] S*V equals five year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders.

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc. *The Value Line, Investment Survey,* Edition 1, June 13; 1997, Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

Duquesne Light Company
S and V Data, Comparable Group of Companies

Company	S 1992	1993	1994	1995	1996	Average S[1]	V [2]	S*V
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	[(f)*(g)] (h)
Carolina Power & Light Co.	0.0000	0.0000	-0.0414	-0.0486	-0.0107	-0.0201	0.5274	-0.0106
Central and South West Corp.	0.0006	0.0000	0.0163	0.0177	0.1426	0.0354	0.3192	0.0113
Cinergy Corp.	0.0247	0.0252	0.1393	0.0237	0.0001	0.0426	0.5120	0.0218
DTE Energy Co.	0.0000	0.0000	-0.0173	0.0000	0.0000	-0.0035	0.1935	-0.0007
Eastern Utilities Associates	0.0334	0.1649	0.0272	0.0156	0.0000	0.0482	-0.0440	-0.0021
Empire District Electric Co.	0.0340	0.0323	0.0257	0.1106	0.0993	0.0604	0.2990	0.0181
GPU, Inc.	0.0000	0.0514	0.0000	0.0582	0.0000	0.0219	0.2605	0.0057
Green Mountain Power Corp.	0.0347	0.0418	0.0359	0.0413	0.0414	0.0390	0.0830	0.0032
Idaho Power Co.	0.0921	0.0407	0.0192	0.0000	0.0000	0.0304	0.4144	0.0126
KU Energy Corp.	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4567	0.0000
Minnesota Power & Light Co.	-0.0014	0.1120	0.0017	0.0109	0.0309	0.0308	0.3411	0.0105
Nevada Power Co.	0.1611	0.1915	0.1115	0.0433	0.0465	0.1108	0.2077	0.0230
OGE Energy Corp.	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4422	0.0000
PECO Energy Co.	0.0030	0.0069	0.0005	0.0034	0.0024	0.0033	0.1105	0.0004
PP&L Resources, Inc.	0.0025	0.0027	0.0273	0.0312	0.0282	0.0184	0.2548	0.0047
St. Joseph Light & Power Co.	-0.0059	0.0008	-0.0354	-0.0006	0.0160	-0.0050	-0.3171	0.0016
United Illuminating Co.	0.0081	0.0041	0.0002	0.0010	0.0001	0.0027	0.0023	0.0000
						0.0244	0.2390	0.0059

[1] Average of five most recent years.
[2] V = (1-(1995 Book Value per Share/Average Stock Price)).

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
Factset Security Price History Report.

Duquesne Light Company
EPS Growth Estimate

Company	EPS 1996	EPS 2000-2002 Estimated	Estimated Growth [1]
	---------(Dollars)--------		--(Percent)--
	(a)	(b)	(c)
Carolina Power & Light Co.	$ 2.66	$ 3.10	3.11 %
Central and South West Corp.	1.43	2.00	6.94
Cinergy Corp.	2.12	2.80	5.72
DTE Energy Co.	2.13	3.25	8.82
Eastern Utilities Associates	1.50	1.90	4.84
Empire District Electric Co.	1.23	1.70	6.69
GPU, Inc.	2.47	3.75	8.71
Green Mountain Power Corp.	2.22	2.55	2.81
Idaho Power Co.	2.21	2.45	2.08
KU Energy Corp.	2.17	2.50	2.87
Minnesota Power & Light Co.	2.28	2.75	3.82
Nevada Power Co.	1.56	1.85	3.47
OGE Energy Corp.	3.25	3.50	1.49
PECO Energy Co.	2.24	2.55	2.63
PP&L Resources, Inc.	2.05	2.10	0.48
St. Joseph Light & Power Co.	1.32	1.65	4.56
United Illuminating Co.	2.88	3.55	4.27
	$ 2.10	$ 2.59	4.31 %

[1] Growth equals [(2000-2002 estimate/1996 actual)^0.20]-1.

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
The Value Line, Investment Survey, Edition 1, June 13, 1997; Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

Duquesne Light Company
Selling and Issuance Cost Evidence

	Public Offering Amount	Underwriter's Discount	Direct Costs	Total Costs	Selling and Issuance Cost
	(Dollars)				(Percent) [(d)/(a)]
	(a)	(b)	(c)	(d)	(e)
8-Nov-79	$ 53,200,000	$ 2,470,000	$ 190,000	$ 2,660,000	5.00 %
12-May-80	59,000,000	2,060,000	180,000	2,240,000	3.80
22-Sep-81	49,500,000	2,060,000	176,000	2,236,000	4.52
Average	$ 53,900,000	$ 2,196,667	$ 182,000	$ 2,378,667	4.44 %

Source: Docket No. R-821945, Duquesne Exhibit No. 12A, Schedule 12, page 4 of 14.

Past Electric Utility Rate Decisions
1995-1997

Exhibit JDM - 12

Date	Utility	ROE		Distribution Point	Frequency
4/17/95	Cleveland Elec. Illum. (OH)	12.59		10.20	-
4/17/95	Toledo Edison (OH)	12.59		10.70	2
4/27/95	Central Louisiana Electric (LA)	12.25	(1)	11.20	5
5/15/95	PSI Energy (IN)	11.00	(2)	11.70	7
5/25/95	Orange & Rockland Utilities (NY)	10.40		12.20	4
6/1/95	Northern States Pwr (WI)	11.30		12.70	3
6/12/95	Union Electric (MO)	13.30	(3)	13.20	-
7/10/95	South Carolina Elec. & Gas (SC)	12.00		13.70	-
7/28/95	Rochester Gas & Electric (NY)	11.20			
9/15/95	Green Mountain Power (VT)	11.25	(4)		
9/21/95	Montana Power (MT)	11.00			
10/17/95	Central Vermont Public Service (VT)	11.00			
11/8/95	PacifiCorp (WA)	11.25			
12/5/95	Arizona Public Service (AZ)	11.25	(5)		
3/15/96	Northern States Power (WI)	11.30			
3/27/96	United Illuminating (CT)	11.50			
8/2/96	Nantahala Power & Light (NC)	11.00	(4)		
10/15/96	MidAmerican Energy (IL)	11.75			
1/3/97	Citizens Utilities (AZ)	10.70			
2/13/97	Wisconsin Electric Power (WI)	11.80			
2/20/97	Wisconsin Public Service (WI)	11.80			
3/6/97	Wisconsin Power and Light (WI)	11.70			
3/31/97	Central Power and Light (TX)	10.90			
Average		11.51			
Median		11.30			

Notes: The following decisions did not include a provision for ROE

Black Hills P&L (SD)	2/1/95
Empire District Elec. (MO)	3/17/95
Entergy Gulf States (LA)	5/31/95
Tuscon Electric Power (AZ)	6/13/95
Kansas Gas & Electric (KN)	8/17/95
Kansas Power & Light (KN)	8/17/95
PacifiCorp (OR)	9/1/95
U.G.I. Corporation	1/26/96
Entergy Louisiana (LA)	4/15/96
Kansas City Pwr. & Lt. (MO)	5/28/96
American Electric Power West Virgina (WV	6/8/96
Entergy New Orleans (LA)	1/9/97
OG&E Electric Services (OK)	1/23/97
Centerior Energy (OH)	1/30/97
Puget Sound Energy (WA)	2/5/97
GPU Energy (NJ)	3/24/97

(1 Includes rate stabilization plan that caps earnings for 5 years, but allows for an equal sharing of earnings between a 12.25% and 13% ROE.
(2 Company may retain earnings up to a 12% ROE.
(3 ROE capped at 13.3%.
(4 Estimated.
(5 Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

Sources: REGULATORY FOCUS, Regulatory Research Associates, Inc. "Major Rate Case Decisions -- January-March 1997," and "Major Rate Case Decisions--January 1985-December 1996."

DUQUESNE LIGHT COMPANY

MARKET-TO-BOOK RATIOS IN EXCESS OF 1.0 SHOULD BE EXPECTED FOR REGULATED UTILITIES

This Exhibit introduces a model to examine and explain some of the factors that affect a company's market-to-book ratio. The model illustrates why it is normal for the market-to-book ratio to differ from 1.0. It shows in particular why, in periods of low inflation, a ratio in excess of 1.0 should be expected. I start from a "Fama-French" model, modifying and simplifying it for the specific case of a regulated utility.[1] This model sets the market value of a company as the discounted stream of expected future dividends. My basic model is simplified, considering an all-equity utility that finances its investments through retained earnings. Later in this Exhibit, I relax some of these conditions in order to investigate the effects on the market-to-book ratio.

A. The Basics of the Model

Dividends in each year t are represented by:

(1) $$D_t = EI_t + DP_t - I_t$$

where EI_t is equity income, DP_t is depreciation and I_t is investment outlays. Equity income is earnings before extraordinary items but after depreciation, taxes and interest. Using accounting principles (assuming that there is no preferred stock):

(2) $$EI_t = REV_t - C_t - DP_t - T_t$$

where REV_t are revenues, C_t are costs and T_t are taxes. Furthermore, we can separate revenues and costs into their regulated and unregulated parts:

[1] For further reference, see: Fama, Eugene F. and Kenneth R. French, "Size and Book-to-Market Factors in Earnings and Returns," *Journal of Finance,* Vol. L, No. 1, March 1995.

(3) $$REV_t = REV_t^R + REV_t^U ;and$$

$$C_t = C_t^R + C_t^U$$

where an R superscript denotes regulated and a U superscript denotes unregulated. Finally, we can define revenues for a certain category l (regulated or unregulated) as:

(4) $$REV_t^l = \sum_{h=1}^{j} p_{h,t}^l \bullet q_{h,t}^l$$

where a subscript h indicates a particular service (for j available services), p represents the price, and q quantity.

For any year $t+i$, expected dividends are:

(5) $$E_t D_{t+i} = E_t\left[EI_{t+i} + DP_{t+i} - I_{t+i}\right]$$

Define ρ_t as the cost of capital in period t; ρ_t is the one-period interest rate in period t under certainty. Therefore, the discount rate to be used at period T is:

(6) $$R_T = \prod_{\tau=1}^{T}\left(1+\rho_\tau\right)$$

The value of the firm's market equity at t is:

(7) $$ME_t = \sum_{i=1}^{\infty} E_t\left(\frac{EI_{t+i} + DP_{t+i} - I_{t+i}}{R_i}\right)$$

and the ratio of market-to-book-equity is:

(8) $$\frac{ME_t}{BE_t} = \sum_{i=1}^{\infty} E_t\left(\frac{\dfrac{EI_{t+i} + DP_{t+i} - I_{t+i}}{BE_t}}{R_i}\right)$$

where BE_t is book equity at period t.

The model is then defined by equations (2)-(4), and (8).

Regulators and regulated companies determine the permissible revenue requirement in a rate case. The revenue requirement is used to set rates for the regulated services. The revenue requirement for a regulated company is given by:

(9) $$RR_t = C_t^R + r_t \cdot BE_t + DP_t + T_t$$

where T_t is taxes in time t.

This section has developed a model that explains that the market to book ratio depends on a discounted stream of expected cash flows as can be seen in equation (8). The difference between expected revenues and the revenue requirement, is examined in the next section.

B. The Model Under Perfect Foresight

In this section, I further simplify the model presented above by assuming that the regulator can perfectly foresee the future and determine all the variables according to the information available. Also, I assume that there are no unregulated revenues. Additionally, investment outlays and depreciation are assumed to be identical at each period. Therefore, dividends are equal to equity income, and the book value of the regulated company is the same in nominal terms for all periods. Finally, the cost of capital is assumed to be the same at all periods.

Perfect foresight on the part of the regulator eliminates two sources of uncertainty: (1) the allowed rate of return will equal the true cost of capital; and (2) the regulator can set the revenue requirement equal to the expected revenues of the company. In other words, if we define r_t as the allowed rate of return in period t, and $\varepsilon_t = r_t - \rho_t$ as the difference between the allowed rate of return set in advance and the actual cost of capital in period t, then:

(10) $$r_t = \rho_t \Rightarrow \varepsilon_t = 0$$

and,

(11) $$\sum_{h=1}^{j} p_{h,t}^R \cdot q_{h,t}^R = RR_t$$

Perfect foresight combined with the absence of unregulated revenues and the equality of depreciation and investment outlays removes uncertainty from the model. Plugging (9), (11) and (12) into (2)-(4) and (8):

$$(12) \qquad \frac{ME_t}{BE_t} = \sum_{i=1}^{\infty} \frac{\rho_{t+i}}{\prod_{T=1}^{i}(1+\rho_T)}$$

The right-hand side of equation (12) is an arithmetic series that equals one as a result of the above assumptions and simplifications. That is, equation (12) becomes:

$$(13) \qquad \frac{ME_t}{BE_t} = 1$$

The result shown in equation (13) indicates that under idealized conditions the market-to-book ratio for a regulated company equals one. These idealized conditions include: (1) no unregulated activities; (2) investments equal depreciation for each period; (3) known fixed cost of capital; and (4) a regulator with perfect foresight.

C. Why Market Value Differs from Book Value

Of course, the future cannot be predicted with certainty—the requirement for equation (13) to hold. There are several sources of uncertainty which cause book and market values to differ. This section offers four examples of sources of such uncertainty: unregulated earnings, regulatory lag, growth expectations, and inflation.

1. Unregulated Earnings

Many utilities earn revenues that are not regulated. Duquesne is one of these. So long as these activities are not loss-making (in which case, the utility would not long continue to provide them), the revenue from these services will exceed their costs. Then:

$$(14) \qquad REV_t^U - C_t^u \geq 0$$

The inequality in equation (14) is a component of equity income. Relaxing the model to allow for unregulated business while maintaining all the other assumptions gives:

(15) $$\frac{ME_t}{BE_t} = 1 + \sum_{i=1}^{\infty} \left[\frac{\dfrac{REV_{t+i}^U - C_{t+i}^U}{BE_t}}{\prod_{T=1}^{i} (1+\rho_T)} \right]$$

The second term in the right-hand side term of equation (15) is positive because of the sign of inequality (14). The market-to-book ratio increases as the result of unregulated services and is greater than 1.0, as we observe from comparing equations (13) and (15).

2. Regulatory Lag

Regulatory lag can be defined as the inability of the administrative process of setting regulated rates to keep up with current events. That is, rates change only as the result of a rate case decision, while costs and the volumes sold for a particular utility can change constantly.

During the interval between rate cases, the utility's earnings depend on its ability to cut costs, increase volumes sold, and generally increase the efficiency of its operations.[2] The variable K_{t+i} of equation (16) shows whether the company profits or loses as the result of regulatory lag.

(16) $$REV_{t+i}^R - C_{t+i}^R = K_{t+i}$$

Relaxing the assumption of no regulatory lag in the model of Section I, the market-to-book value is higher than 1.0 when K_{t+i} is positive. In the past, in periods of high inflation, such regulatory lag represented a considerable problem for utilities—consistent with observed market-to-book ratios less than one in the late 1970s and early 1980s. With little or no inflation, however (which is the case at present), increased efficiency and greater productivity in the industry would argue for a positive K_{t+i}. That is to say, while K_{t+i} could be either positive or negative, reflecting opposing forces such as inflation and productivity, the current market should lead us to expect this term to be positive.

[2] "Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from (continued...)

3. Growth Expectations

Investors in the market form expectations about the future path of the company. Market value is calculated as a forward-looking process. It entails a forecast about the company's costs in the future, how the market will expand (*e,g*, market penetration) and the impact of future regulatory proceedings, among other factors. Investors make their own assumptions and arrive at a general or specific market value for the utility. These expectations affect all future expected earnings (EI_{t+i}). If the expectations of investors are positive (negative), the market-to-book ratio will be higher (lower) than 1.0. An example of positive expectations is when investors believe that the company can cut costs in the future and increase its efficiency, outperforming the regulator's expectations.

4. Inflation Expectations

The real cost of capital depends in part on the expectations of future inflation. The rate of return set by the regulator incorporates inflationary expectations. At times, the rate of return set by the regulator may have a higher forecasted inflation rate than that currently envisioned by investors—for example, because of a change in policy of the Federal Reserve. As a result, the market changes its valuation of the company, relative to its regulatory book value. If the market cost of capital has dropped (increased) since the allowed rate of return was set, the market value for the company increases (decreases) as does the market-to-book ratio.

D. Summary

Regulated utilities earn their equity income as a function of a regulated cost of capital multiplied by a regulated equity rate base. As such, it is reasonable to question why, with such a regulatory model, the market-to-book ratio is rarely equal to 1.0. If regulators have done their job of setting the cost of capital reasonably accurately, why is this so?

(...continued)

a superior performance and have to suffer the losses from a poor one," Kahn, Alfred (1971): *The Economics of Regulation*, John Wiley & Sons, New York.

The model I present here illustrates some of the principal reasons why market-to-book ratios differ from 1.0. First, it shows that the market-to-book ratio equals one only in the case of: (1) a regulator who is perfectly able to predict the future, (2) a utility with no unregulated segments that (3) invests the same amount that is depreciated each period in a market with (4) a known fixed cost of capital. These conditions, however, do not always (or indeed often) hold. Unregulated earnings (which for many utilities like Duquesne are a growing part of total earnings), regulatory lag (which in low inflation periods favors utilities) and growth expectations are all factors that will drive a wedge between market values and book values. In the current market environment, we should expect this wedge to drive market values above book values (which is what we observe in the market for utility common stock).

Internal Rate of Return
Comparison of Findings

	NERA		
	1972 - 1996	1972 - 1992	NARUC [1]
	(Percent)		
	(a)	(b)	(c)
DQE	8.40 %	7.78 %	11.92 %
Electric Utilities	9.44	9.51	14.19
S&P Utilities	11.19	10.99	nr
S&P Industrials	10.49	10.20	12.95

nr not reported

[1] Calculated as an average of returns for 171 holding periods.

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
Electric and Telephone Utility Stockholder Returns: 1972 - 1992, National Association of Regulatory Utility Commissioners, September 13, 1993.
Analysts' Handbook, Standard & Poor's, 1996.

Internal Rate of Return of Electric Utilities
1972 - 1996 and 1972 - 1992 Holding Periods

	Internal Rate of Return	
	1972 - 1996	1972 - 1992
	------------(Percent)------------	
	(a)	(b)
ALLEGHENY POWER SYSTEM	11.05 %	10.81 %
AMERICAN ELECTRIC POWER	8.37	7.97
ATLANTIC ENERGY INC	9.96	10.54
BALTIMORE GAS & ELECTRIC	10.76	10.64
BANGOR HYDRO-ELEC CO	7.54	8.44
BOSTON EDISON CO	8.42	8.47
CAROLINA POWER & LIGHT	9.68	9.22
CENTRAL & SOUTH WEST CORP	9.18	9.44
CENTRAL HUDSON GAS & ELEC	9.17	9.20
CENTRAL MAINE POWER CO	7.81	8.73
CILCORP INC	8.62	8.60
CIPSCO INC	9.51	9.10
CMS ENERGY CORP	5.24	4.02
COMMONWEALTH ENERGY SYSTEM	11.55	11.49
CONSOLIDATED EDISON OF NY	13.79	14.28
DELMARVA POWER & LIGHT	10.02	10.29
DOMINION RESOURCES INC	9.04	9.07
DPL INC	9.49	9.07
DQE INC	8.40	7.78
DTE ENERGY CO	6.09	4.71
DUKE POWER CO	11.74	11.51
EASTERN UTILITIES ASSOC	7.98	8.31
EDISON INTERNATIONAL	9.69	8.62
EL PASO ELECTRIC CO	4.46	4.63
EMPIRE DISTRICT ELECTRIC CO	9.87	10.68
ENTERGY CORP	5.69	5.87
FLORIDA PROGRESS CORP	8.95	8.93
FPL GROUP INC	9.22	8.95
GPU INC	8.80	8.33
HAWAIIAN ELECTRIC INDS	10.69	11.31
HOUSTON INDUSTRIES INC	6.54	6.35
IES INDUSTRIES INC	9.66	9.76
ILLINOVA CORP	6.02	5.75
INTERSTATE POWER CO	9.67	9.95

Internal Rate of Return of Electric Utilities
1972 - 1996 and 1972 - 1992 Holding Periods

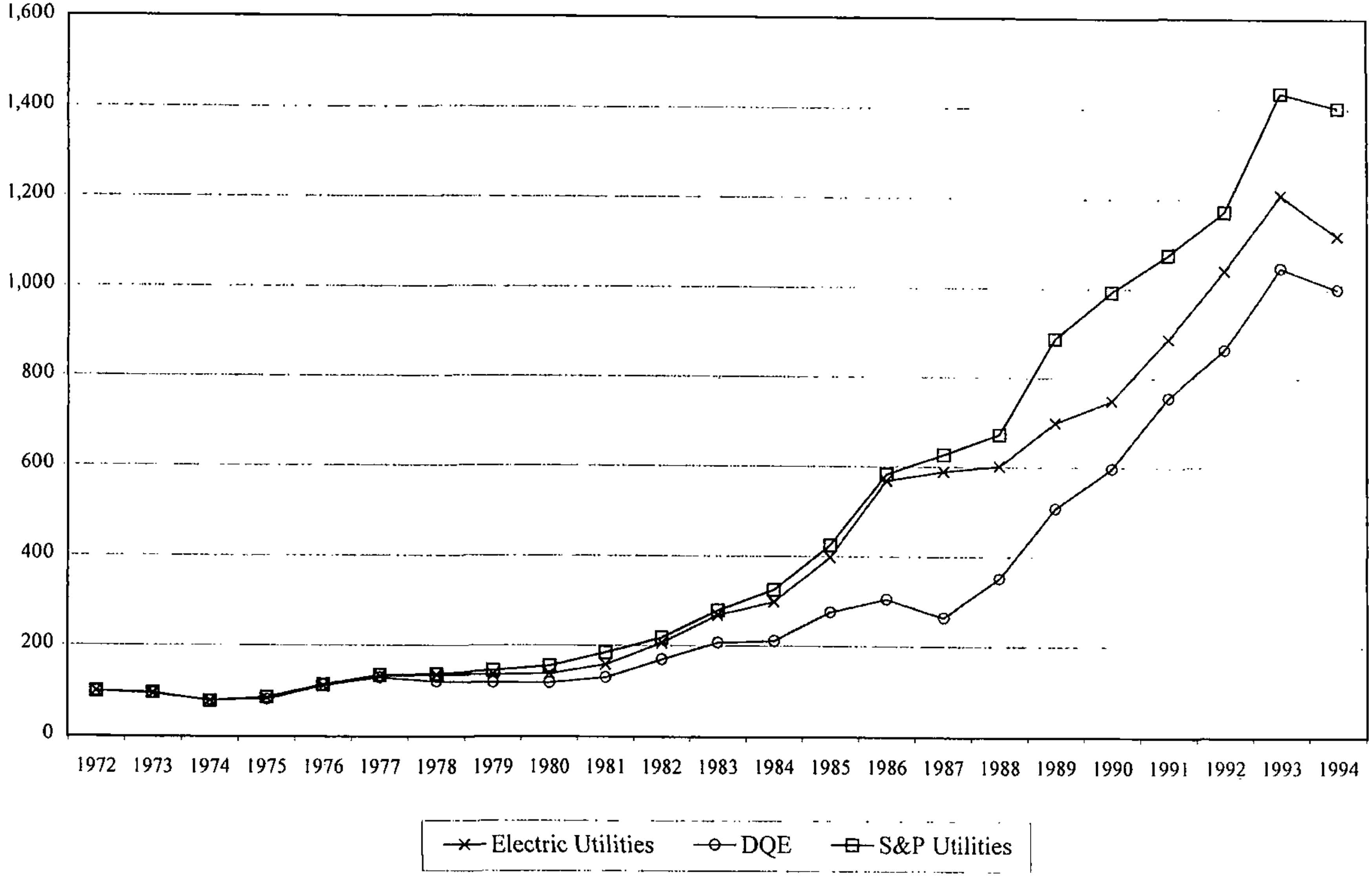
	Internal Rate of Return	
	1972 - 1996	1972 - 1992
	-(Percent)-	
	(a)	(b)
IPALCO ENTERPRISES INC	10.61	10.68
KANSAS CITY POWER & LIGHT	10.55	10.49
KU ENERGY CORP	9.97	10.09
LG&E ENERGY CORP	8.16	7.51
LONG ISLAND LIGHTING	5.66	5.97
MDU RESOURCES GROUP INC	11.82	11.66
MINNESOTA POWER & LIGHT	11.58	12.32
MONTANA POWER CO	7.65	8.16
NEVADA POWER CO	10.07	10.20
NEW ENGLAND ELECTRIC SYSTEM	11.88	12.19
NEW YORK STATE ELEC & GAS	9.19	9.73
NIAGARA MOHAWK POWER	7.36	8.72
NIPSCO INDUSTRIES INC	6.01	4.82
NORTHEAST UTILITIES	8.56	9.27
NORTHERN STATES POWER/MN	11.87	12.03
OGE ENERGY CORP	7.96	7.83
OHIO EDISON CO	7.73	7.71
ORANGE & ROCKLAND UTILITIES	10.51	10.89
OTTER TAIL POWER CO	11.99	12.50
PACIFICORP	9.56	9.97
PECO ENERGY CO	8.38	8.32
PG&E CORP	9.57	10.42
PINNACLE WEST CAPITAL	8.57	8.14
PORTLAND GENERAL CORP	8.79	7.53
POTOMAC ELECTRIC POWER	12.11	12.54
PP&L RESOURCES INC	10.07	10.55
PUBLIC SERVICE CO OF COLO	8.64	8.15
PUBLIC SERVICE CO OF N MEX	6.96	6.61
PUBLIC SERVICE ENTRP	10.07	10.21
PUGET SOUND ENERGY INC	10.05	10.37
ROCHESTER GAS & ELECTRIC	8.88	9.11
SCANA CORP	9.69	9.38
SIERRA PACIFIC RES	8.76	8.61
SIGCORP INC	13.06	13.67

Internal Rate of Return of Electric Utilities
1972 - 1996 and 1972 - 1992 Holding Periods

	Internal Rate of Return	
	1972 - 1996	1972 - 1992
	(Percent)	
	(a)	(b)
SOUTHERN CO	9.80	9.39
SOUTHWESTERN PUBLIC SVC CO	11.92	12.21
ST JOSEPH LIGHT & POWER	10.92	11.44
TECO ENERGY INC	11.09	11.07
TEXAS UTILITIES CO	6.90	6.81
TUCSON ELECTRIC POWER CO	9.32	9.68
UNICOM CORP	6.94	7.13
UNION ELECTRIC CO	10.21	10.23
UNITED ILLUMINATING CO	8.57	8.77
UTILICORP UNITED INC	14.06	14.55
WASHINGTON WATER POWER	10.04	10.10
WESTERN RESOURCES INC	10.06	10.15
WISCONSIN ENERGY CORP	14.09	14.69
WPL HOLDINGS INC	11.68	12.38
WPS RESOURCES CORP	13.07	13.49
Average	9.44 %	9.51 %

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
Electric and Telephone Utility Stockholder Returns: 1972 - 1992, National Association of Regulatory Utility Commissioners, September 13, 1993.

DQE, Electric Utilities and S&P Utilities Indices
Total Shareholder Returns
1972 - 1994



Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
Analysts' Handbook, Standard & Poor's, 1996.

DQE, Electric Utilities and S&P Utilities Indices
Total Shareholder Returns
1972 - 1994

	Electric Utilities (a)	DQE (b)	S&P Utilities (c)
1972	100	100	100
1973	95	95	96
1974	78	79	78
1975	84	81	87
1976	111	113	114
1977	133	130	136
1978	136	121	138
1979	137	119	146
1980	138	119	156
1981	159	130	185
1982	206	170	217
1983	267	207	278
1984	297	211	324
1985	398	274	425
1986	568	304	582
1987	589	263	627
1988	601	351	671
1989	698	507	887
1990	748	597	992
1991	887	755	1,074
1992	1,040	863	1,172
1993	1,209	1,046	1,436
1994	1,118	1,000	1,403

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
Analysts' Handbook, Standard & Poor's, 1996.

FILE CONTINUED