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AES Power, Inc.
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AIG Trading Company
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Alliance Strategies
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Alternate Power Source, Inc.
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American Power Exchange Corporation
ATTN: Eric Patterson
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AMOCO Power Marketing Corporation
ATTN: Frederick T. Kolb
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Houston, TX 77079

ANP Energy Direct Company
ATTN: Elaine G. Rollins
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Aquila Power Corporation
ATTN: Jerry F. Coffey
2533 North 117th Avenue,
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~~Ark Exploration Company (took over NorAm)~~
ATTN: SEE NoRam

Ashton Energy Corp.
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Associated Power Services
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Astra Power, Inc.
ATTN: Rita Sharp, Vice President
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Topeka, KS 66601

Audit Pro, Inc.
ATTN: James Keene
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San Francisco, CA 94111

Black Creek Hydro, Inc.
ATTN: Martin W. Thompson, V.P.
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Bonneville Fuels Management Corporation
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50 West 300 South, Suite 600
Salt Lake City, UT 84101

Boyd Rosenne & Associates
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1200 Park Center, 525 South Main Street
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Btu Power, Inc.
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C.C. Pace Energy Services
ATTN: Paul Meyers
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Fairfax, VA 22033

Calpine Power Marketing, Inc.
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Slate, et al
1440 New York Avenue, NW,
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Camelot Energy Services
ATTN: Dennis M. Lawler
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ATTN: Michael R. Kutsch, President
470 Atlantic Avenue,
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Cenergy, Inc.
ATTN: Thomas J. Lewis, President
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Cenerprise, Inc.
ATTN: Stephen J. Beuning, Director
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Citizens Lehman Power LP
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Citizens Power and Light Corporation
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CMEX Energy, Inc. (SEE "GLOBAL PETROL")
ATTN: Ron Bates, V.P. Corporate Development
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CNB/Olympic Gas Services
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CoEnergy Trading Company
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Houston, TX 77010

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KCS Energy Marketing Services, Inc. !!!SEE
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MidCon Power Services Corporation
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CO)
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National Fuel Gas Distribution Corporation
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National Fuel Resources, Inc.
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National Power Exchange Corporation
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North American Power Brokers, Inc.
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POWER MARKETER LIST:05/17/97

POWER MARKETER LIST:05/17/97

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June 10, 1997

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Dear Mr. Irvin,

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

Please send RFP to

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Thank you.

Tom Pelscci

Post-it* Fax Note	7671	Date	6-16-97	# of pages	1
To	FAYE	From	SANDY		
Company	RADDEN ARPS	Cc.	DKCO		
Phone #	202-371-7071	Phone #	412-393-6233		
Fax #	202-371-7934	Fax #	412-293-8647		

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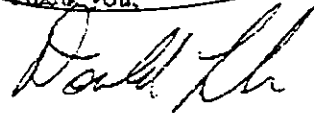
MESSAGE:

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



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 today's 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.



411 Seventh Avenue
Pittsburgh, PA 15219

NEWS

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.

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NATIONAL NEWSLINES

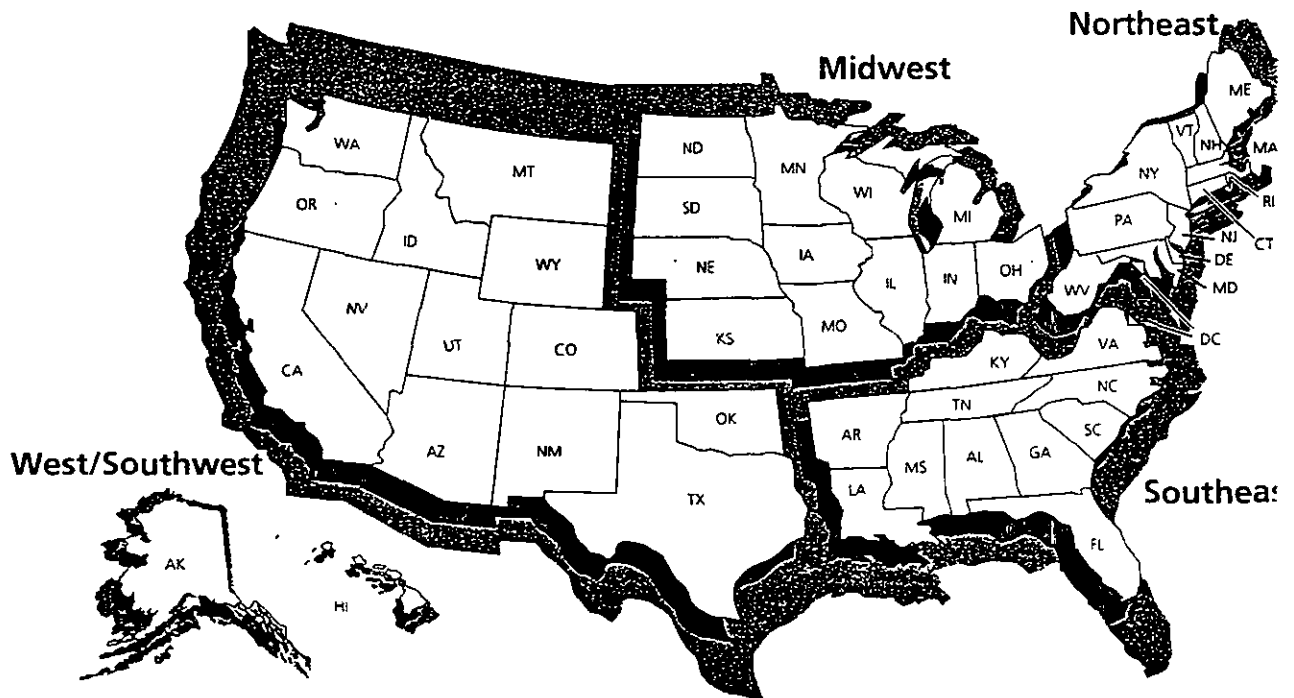
NATIONAL NEWSLINES

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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 News
 Elmira
 Star-Gazette
 Mamaroneck
 Daily Times
 Mt. Vernon
 Daily Argus
 New Rochelle
 Standard-Star
 New York City
 Times • Daily News
 Newsday • Post
 Wall Street Journal
 Journal of Commerce
 Investor's Business Daily
 Dow Jones • Reuters
 AP • UPI
 AFX News Service
 Bloomberg News Service
 Fitch Investors Service
 Moody's Investors Service
 Standard & Poor's
 S&P MarketScope
 Knight-Ridder Financial
 Munifacts News Wire
 Marker News Service
 Cable News Network
 New York - 1
 WABC-TV • WNBC-TV
 WCBS-AM
 CBS Radio Network
 American Stock Exchange
 National Association of
 Securities Dealers
 New York Stock Exchange
 Asahi Shimbun
 Dempa Shimbun
 EFE Spanish News Agency
 Financial Times of London
 German Economic News (VWD)
 German Press Agency (DPA)
 International Herald Tribune
 NHK (Japan Broadcasting Co.)
 Nikkei Weekly
 Jiji Press
 Kyodo News Service

US1

OKLAHOMA

Oklahoma City
Daily Oklahoman • Datatimes
In-Depth Digest
Tulsa
World

OREGON

Eugene
Register-Guard
Portland
Oregonian • AP • KXL-AM
KATU-TV • KGW-TV
KOIN-TV • KPTV-TV
KEX-AM • KINK-FM
Bloomberg Business News
Marples
Reuters
Business Week (NW Region)
New York Times Bureau
Daily Journal of Commerce
Business Journal
Salem
Statesman-Journal

PENNSYLVANIA

Allentown
Morning Call
WFMZ-TV • WFMZ-FM
Altoona
Mirror
Beaver County
Times
Bloomsburg
Press-Enterprise
NE Penn. Business Journal
Butler
Eagle
Doylestown
Intelligencer/Record
Easton
Express-Times
Erie
Morning News • Times
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
WHP-TV • WHTM-TV
WHP-AM/FM
Hazleton
Standard-Speaker
Huntingdon Valley
The Sports Network
Johnstown
Tribune-Democrat
Lancaster
Intelligencer Journal
New Era • WGAL-TV

Lansdale

Reporter
Lebanon
WLYH-TV
Levittown/Bristol
Bucks County Courier-Times
Lewistown
Sentinel
McKeesport
Daily News
Moosic/Scranton
WNEP-TV
Norristown
Times Herald
North Hills
News Record
Paoli
Autofacts
Philadelphia
Daily News • Inquirer
Tribune • AP • UPI • Reuters
KYW-TV • WCAU-TV
WPVI-TV • WTXF-TV
WUSL-FM • WWDB-FM
KYW-AM • WDAS-FM
WHYY-FM • WMGK-FM
WPEN-AM
New York Times Bureau
City Hall Newsroom
Dun & Bradstreet
Business Week
The Inquirer News Tonight
Philadelphia Business Journal
Philadelphia Stock Exchange
Metro Traffic
Shadow/Express Broadcast Svcs.
Fairchild Pubs. (10 pubs.)
Pittsburgh
Post-Gazette
Pittsburgh Tribune-Review
AP • Reuters • UPI
Dow Jones/Wall Street Journal
Industry.Net
Bloomberg Business News
KDKA-TV • WPXI-TV
WTAE-TV • WLTI-FM
KDKA-AM • KQV-AM
WYJZ-AM/WAMO-FM
WTAE-AM • WWSW-AM & FM
American Urban Radio Network
Business Times
Business Week
American Metal Market
Iron Age
Portstown
Mercury
Primos/Chester
Delaware County Daily Times
Reading
Eagle & Times
Scranton
Times • WYOU-TV
Sharpsburg
Herald

State College

Centre Daily Times
Tarentum
Valley News Dispatch
Uniontown
Herald-Standard
Washington
Observer-Reporter
West Chester
Daily Local News
Wilkes-Barre
Citizens' Voice • Times Leader
York
Daily Record • Dispatch
WSBA-AM • WPMT-TV

RHODE ISLAND

Providence
Bulletin • Journal

SOUTH CAROLINA

Charleston
Post & Courier
Columbia
State • AP
Florence
Morning News
Greenville
Piedmont • News
WYFF-TV
Myrtle Beach
Sun News
Rock Hill
Herald
Spartanburg
Herald-Journal • WSPA-TV

SOUTH DAKOTA

Aberdeen
News • KSDN-AM/FM
Brookings
Record
Huron
Plainsmen
Mitchell
Daily Republic
Pierre
Capital Journal
Press & Dakotan
Rapid City
Rapid City Journal
KEVN-TV • KOTA-TV/AM
Sioux Falls
Argus Leader
KBRK-AM
KELO-TV • KDLT-TV
KUSD-TV
Spearfish
Daily Queen City Mail
Wazertown
Public Opinion

TENNESSEE

Chattanooga
Free Press • Times
Jackson
Sun
Johnson City
Press
Kingsport
Times-News
Knoxville
News-Sentinel
Memphis
Commercial Appeal
Nashville
Banner • Tennessean
Business Journal
Oak Ridge
Oak Ridger

TEXAS

Amarillo
Globe-Times
Austin
American-Statesman
KVUE-TV • KOKE-AM
Austin Business Journal
Conroe
The Conroe Courier
Corpus Christi
Caller-Times
Dallas
Morning News
DFW People
New York Times
Suburban Daily News
AP • UPI • Reuters
Dow Jones/Wall Street Jour
KDFW-TV • WFAA-TV
KTVT-TV • KXAS-TV
KRLD-AM
Cable News Network
USA Radio Networks
Texas State Radio Network
Advertising Age
Adweek
Barron's
Business Press
Business Week
Daily Commercial Record
Business Journal
Fairchild Publications
McGraw-Hill Publications
The Texas Lawyer
El Paso
Times
Fort Worth
Star-Telegram
Mid-Cities Daily News
KXAS-TV • WBAP-AM
KSCS-FM
KLIF-AM • KPLX-FM
Garland
Daily News
Grand Prairie
Daily News

Houston

Chronicle • Post
AP • UPI • Reuters • Dow Jones
KPRC-TV • KHOU-TV
KPRC-AM
NBC News Bureau
CUC
The Energy Report
Fairchild Publications
Houston Business Journal
Japan Economic Journal
McGraw-Hill Publications
Gas Daily
Gulf Publishing Co.
Inside Gas Markets
The Morning Report
Offshore Data Services
Oil and Gas Journal
Oil Daily
Ocean Oil Weekly
Petroleum Information
Platt's Oil Gram
Irving
Daily News
Lubbock
Avalanche Journal
Midland
Reporter Telegram
Plano
Star-Courier
Richardson
Daily News
San Angelo
Standard Times
San Antonio
Express News
Business Journal
KENS-TV • WOAI
Waco
Tribune-Herald

UTAH

Logan
Herald Journal
Ogden
Standard Examiner
Provo
Daily Herald
Salt Lake City
Deseret News • Tribune

VERMONT

Burlington
Free Press
Rutland
Herald

VIRGINIA

Newport News
Daily Press
Norfolk
Virginian-Pilot
Richmond
Times-Dispatch • AP
Financial Weekly (Media Gen'l)
Virginia News Network
WRLN/WXRL
Roanoke
Times
Springfield
Journal Newspapers
News Channel 8

WASHINGTON

Bellevue
Journal American
Bellingham
Herald
Bremerton
Sun
Everett
Herald
Kent
Valley Daily News
Longview
Daily News
Olympia
The Olympian/USA Today
Pasco
Tri-City Herald
Seattle/Puget Sound
Post-Intelligencer • Times
AP • UPI • Reuters
Business Week Bureau
Bloomberg Business News
New York Times Bureau
Northland Cable News
KING-TV • KIRO-TV
KOMO-TV • KSTW-TV
KIRO-AM • KMPS-AM & FM
KOMO-AM
Microsoft News Network.
Asia Pacific Journal
Daily Journal of Commerce
Marple's Business Newsletter
Puget Sound Business Journal
Washington CEO
Spokane
Spokesman-Review/Chronicle
AP
KHQ-TV • KXLY-TV
KXLY-AM
Journal of Business
Tacoma
Morning News Tribune
Vancouver
Columbian
Walla Walla
Union-Bulletin
Yakima
Herald-Republic

WEST VIRGINIA

Beckley
Register-Herald
Bluefield
WVVA-TV
Charleston
AP • WCHS-TV
Daily Mail • Gazette
West Virginia Public Radio
Network including:
(WVPW • WVPB
WVPN • WVWV
WVEP • WVPM
WVPG • WVNP)
Clarksburg
Exponent • Telegram
WBOY-TV
Huntington
Herald-Dispatch
WOWK-TV
Martinsburg
Journal
Morgantown
Dominion-Post
Metro News Radio Network
(58 Statewide Affiliates)
Oak Hill
WOAY-TV
Parkersburg
News • Sentinel
Wheeling
Intelligencer • News-Register
WTRF-TV
WVOK-FM • WVVA-AM

WISCONSIN

Appleton
Post-Crescent
Eau Claire
Leader-Telegram
WEAU-TV
WAYY-AM • WAXX-FM
Green Bay
Press-Gazette
News Chronicle
WLUK-TV
LaCrosse
Tribune
Madison
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
Rhineland
WJFW-TV
Sheboygan
The Press
Wausau
The Daily Herald

WYOMING

Cheyenne
Tribune Eagle

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 Abelow, Ihasz
 ABN Bank
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 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.
 Barnet 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 Services
 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.
 Dierche & 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

Management
(A.G.) & Sons
Investment Advisors
Associates
Investment Sys. of Texas
Luerin & Turner
Investment Mgt.
Capital Management
Capital Management
Securities
Law Fund Mgt.
Research
National Bank
Capital
Capital Partners
Insurance Group
Investment
Investors
& Co.
Holding Co.
Walter Watts
Management & Research
Management Assoc.
Concept
Concept
Programs
Company Corp.
Analysis Securities
Investment Management
Bank System
Chicago
City Capital Corp.
Investment Management
National Bank of Chicago
Security Investment
Management
Wisconsin Investment Mgt.
Investments
Investors Service
Investment Management
State Board of Admin.
Fontaine Associates
Hann & Leff Associates
Financial Group
Frank & Co.
Russell Trust Co.
Investment Resources
Investment Securities Co.
Investment Welwood
Revy Investment Co.
Investment Capital Management
Securities
Investment Selz
Investment Ili & Co.
Investment Capital
Investment Management
Investment Advisors
Investment, Turker
Investment
Investment Asset Management
Investment Electric Investment Corp.
Investment Weiss Associates
Investment Virginia State Retirement Sys.
Investment Investment, Martison & Co.
Investment & Co.
Investment Financial Management
Investment, Sachs & Co.

Gordon & Co.
Gordon Capital
Gorham 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
Instinct
Institutional Capital Corp.
Insurance Company of the West
Interallianz
International Capital Access
International Pacific Securities
Interstate/Johnson Lane
Interwest 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, Abbert & 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 Advisers

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
McGlenn Capital Management
McIntosh Hanson Hoare Govett
McKenzie, Walker Inv. Mgt.
Mellon Bank
Mercantile Bank
Merchants Insurance Group
Mercury Securities
Merrill Lynch
Merrill Lynch Asset Management
Mesirov & 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

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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
Northwest 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 & Refsnos
Raymond James & Associates
Regal Capital Company
Regent Investors Services
Reich & Tang
Reimer & Koger Associates
Reliance Insurance
Republic National Bank
G.W. Ringo & Company
Robert W. Baird & Co.
Roberson, 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 Associates
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
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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.

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
Barton's
Best Insurance ~~Magazine~~
Reports (BIMR)
BestWeek
Best's Review
Bond Buyer
Bond World
Boston Business ~~Journal~~
Bowman's Accounting ~~Report~~
Branch Automator ~~Report~~
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 Markscope
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
Firstfacts
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
CPI 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
C4I 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 EntertainNet 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 Rpt.
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 Trends
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/Daracom Group
Bay Area Computer Currents
Beyond Computing
BOC Week
Boston Computer Currents
Branch Automation News
Broadband Networking
Broadband Systems & Design
Business Communications Rev
Business Research Group
Business Strategies
BusinessTimes
Byte Magazine
C/D ROM Professional
C3I
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	Networking Management	R & D Magazine	Telecommunications Magazine
LAN Times	New Media	Radio Communications Report	Telecommunications Reports
Land Mobile Radio News	News & Review	Release 1.0	Telecommunications Reports Int'l
Laser Focus World	Newsbytes News Network	Report on AT&T	Telecommunications Reports
Laser Report	NextREVIEW	Report on IBM	Wireless News
Library Software Review	Object-Oriented Tools Bulletin	Reseller Management	Telecommunications World
Light Wave	OCLT Systems & Services	Reseller World	Teleconnect
Link Resources Corp.	Office World News	Reseller World Magazine	Telephone Industry Directory
Link Up	Officemation Product Reviews	Retail Info Systems News	Telephone News
Local Area Networks Newsletter	Online Magazine	Retailing Tech. & Operations	Telephony
Lookout Point Interactive	Online Review	RF Designs	Test & Measurement World
Lyra	Online Tonight	RS/Magazine	The A: Drive
M.D. Computing	Open Computing	Run	The Age
Mac Home Journal	Open Systems News	Rural Telecom	The ATM Report
MAC TV	Open Systems News	Russian Fiber Optics & Telecom Magazine	The Bishop Report
Macintosh Update	Oregon Technology Newsletter	Satellite Communications	The Bulletin
MacTech Magazine	OS/2 Developer	Satellite News	The Cobb Group
MacUser	OS/2 Magazine	Scientific Computing & Automation	The EFT Sourcebook
MacWeek	Packaged Software	Selling Networks	The HP Chronicle
Macworld	Patricia Seybold Group	Semiconductor International	The Local Netter Newsletter
Management InfoCorp.	PC Computing	Sensors Magazine	The Long-Distance Letter
Managing Automation	PC Dealer	Service News Magazine	The MAP Netter
Manufacturing Systems	PC Digest/Microsystems Report	Seybold Report on Desktop Publishing	THE NET
Marketing Computers	PC Digest/Peripherals Report	Seybold Report on Publishing Systems	The Operator
MarketPro	PC Entertainment	Silicon Graphics World	The OSI Netter
Memory Card Systems & Design	PC Gamer	Silicon Valley Business (TV)	The PC Netter
Meta Group	PC Graphics & Video	Smart Magazine	The Red Herring
Metropolitan Area Networks	PC Graphics Report	SNA Communications Report	The Sun Observer
Micro Publishing Report	PC Laptop	Softpub Resource Letter	Token Perspective Newsletter
Microsoft Systems Journal	PC Letter	Software Developer & Publisher	TR Wireless News
MicroTimes	PC Magazine	Software Digest Ratings Report	Training Electronics
Midrange Systems	PC News	Software Industry Bulletin	Tribuna Informatica
MIPS World	PC Novice	Software Industry Report	TV Technology
Mobile Office	PC Plus (U.K.)	Software Magazine	Twice
Mobile Phone News	PC Press	Software Marketing Journal	Unigram.X
Mobile Product News	PC Shopping Show Inc.	Software Trader	Unisys World
Mobile Products Europe	PC Street Price Index	Solid State Technology	Unisys World 4 Europe
Mobile Satellite News	PC Techniques	SPARC	UNIX Review
Modern Office Technology	PC Today	STACKS	Upgrade Magazine
Monash Information Services	PC TV Productions	State Telephone Reg. Report	Upside Magazine
Monash Software Newsletter	PC User	Storage Systems Today	User Friendly Computer News & Reviews
Mondo 2000	PC Week	Strategy Network Consulting	User Friendly Reseller Resource
Monitor	PC Week Labs	Sun Expert	VAR Business
Multichannel News	PC World	Sun Observer	VAX Professional
Multimedia Business Report	PC World Online	Sun World	Venture Finance
Multimedia Daily	PC+	Superconductor Week	Via Satellite
Multimedia Monitor	Peak Computing Magazine	Systems & Network Integration	Videogame Advisor
Multimedia Review	Personal Computer Network	Systems Integration & Marketing	Video Marketing Newsletter
Multimedia Week	Personal Electronic News	T E & M's Telecom Asia	Video Marketing Surveys & Forecasts
Multimedia Wire	Personal Systems	Technical Employment News	VideoNews International
Multimedia World	Personal Workstation	Technical Enterprises	Video Pro
National Report On Computers & Health	Perspective	Technologic Partners	Video Technology News
Natvaridem	Phone+	Technology & Media	Video Toaster User
NCR Connection	PhotoMedical	Telco Competition Report	ViewText
.net The Internet Magazine (UK)	Photonics Spectra	Telecom Data Report	Virtual Reality Report
NETFAX News	PickWorld	Telecom Market Letter	Voice Information
NetGuide	Plastic Optical Fiber	Telecom Strategy Letter	Voice Technology News
Nerware Solutions	Popular Electronics	Telecommunications	Wafer News Confidential
Nerware Technical Journal	Portable Computing	Telecommunications Alert	Wall Street Computer Review
Network Computing	Portland Computer Bits	Telecommunications	Wang in the News
Network Computing Magazine	Presentation Solutions	Telecommunications	Washington Technology
Network Computing News	Presentations	Telecommunications	Washington Trade Report
Network Management Systems	Printed Circuit Fabrication	Telecommunications	Web Developer
Network Technical Services	Probe Research	Telecommunications	Web Review
Network Week (U.K.)	Publish	Telecommunications	Web Techniques
Network World	Puget Sound Computer User	Telecommunications	
	Quick Response News	Telecommunications	
		Billing Reports	

TRADE PUBLICATIONS

Exhibit RAI-6

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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

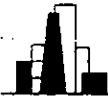
Forest Industries
Pulp & Paper
Pulp & Paper International
Pulp & Paper Week
World Wood

SCONSIN

Mississippi

ILLINOIS

transactions are highly restricted as to who may be shown offerings, bid or transfer these interests. Investing in or offering early stage company interests entails substantial risk. No guarantee either of profit or of a successful offering is given or implied. Consult your investment advisor before investing or selling.



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Angels are high net worth investors who invest directly in small companies which need either start-up or expansion capital.

Member firm NASD/SIPC

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



Of all the reasons why AK Steel chose to build its new state-of-the-art steel mill in

Steel needed help finding solution, John Taylor was there.

e. And there. And there.

Rockport, Indiana, one of the most compelling was John Taylor. Because not every state has people with the uncanny ability to meet local officials here, talk

with state officials there and deliver a proposal out-of-state, all seemingly at the same time. For AK Steel, such a can-do attitude combined with our unmatched financial incentives made Indiana the unanimous choice.

To learn how Indiana can respond to your many and varied economic development needs, talk to the one-and-only John Taylor at 1-800-463-8081.

Indiana

The challenged claims are discredited by one university historian who offers them an entertaining explanation: Southerners suggest that some blacks

Exhibit RAI-7
Page 1 of 1

should be made that no one in the South knew that the Confederacy was about to fail and white supremacy. However, facts of ante-bellum history are undeniable: 1) It was the secession issue that brought the country to war; 2) no one in the political mainstream on either side of that issue substantively opposed slavery and white supremacy.

The federal government had no intention of abolishing slavery during the ante-bellum era, and it was in fact a 45-year period of grossly inequitable tariff policy that actually alienated the loyalty of Southerners from Washington. When threats of secession emerged, they did not question the legality of the institution where it was practiced. Instead, they related to the expansion of slavery into new areas from which there was foreseen an impact upon the balance of political power—specifically, the power over the federal tariff, an instrument influencing the economic character of the nation far more profoundly than readily apparent from its ostensible function as primary source of federal government revenues.

Although cotton was well known to have been grown with slave labor, it was never acknowledged by any state that had a stake in the cotton making; on the contrary, it was the states that, by sustaining the tariff, Southern protests, ensured that competition for the cotton would always be limited effectively to domestic buyers. And it is accordingly clear that the explosive growth of slavery was actually fueled by a demand concentrated in the nation's industrial states. Neither was there an initiative from Washington to free slaves by offering financial compensation to slaveholders. And most telling, the South's efforts at appeal of the hated tariff never brought forth a Northern response that envisaged achieving emancipation by means of a quid pro quo.

With conventional historians having established that the federal government went to war for the purpose of crusade against slavery, those infernal Southerners are just sure to ask why, when the government leap-frogged all the measures that might have culminated in an abolition by negotiation, it is inappropriate to conclude that what the leadership of the North's great egalitarian society actually did was reveal itself as a collection of mongers.

DENNIS G. SAUNDERS
Columbia, Md.

Perhaps Nelson Winbush's claim that tens of thousands of blacks will fight for the Confederacy is exaggerated. But whether, as his detractors propose, some or all black Confederate soldiers

Just Serve the Steak And Hold the Sizzle

Your May 22 Money & Investing article "More Firms Use Options to Gamble Their Own Stock" was a great example that 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.

ture 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 base load 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

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_dico.im.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 genera-

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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 capaci-

ty 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.

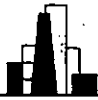
DQE shares closed at \$27.37½ yesterday, down 25 cents from Thursday's close.

SCONSIN

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transactions are highly restricted as to who may be shown offerings, bid or transfer these interests. Investing in or offering early stage company interests entails substantial risk. No guarantee either of profit or of a successful offering is given or implied. Consult your investment advisor before investing or selling.



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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



Duquesne Light

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Of all the reasons why AK Steel chose to build its new state-of-the-art steel mill in Rockport, Indiana, one of the most compelling was John Taylor. Because not every state has people with the uncanny ability to meet local officials here, talk with state officials there and deliver a proposal out-of-state, all seemingly at the same time. For AK Steel, such a can-do attitude combined with our unmatched financial incentives made Indiana the unanimous choice.

Steel needed help finding solution, John Taylor was there. re. And there. And there.

To learn how Indiana can respond to your many and varied economic development needs, talk to the one-and-only John Taylor, at 1-800-463-8081

To learn how Indiana can respond to your many and varied economic development needs, talk to the one-and-only John Taylor, at 1-800-463-8081

Indiana

Exhibit RAI-8
Page 3 of 4

that the Confederacy was about slavery and white supremacy. Perhaps the point should be made that no one in the Southern states during the Confederacy was about slavery and white supremacy. However, facts of ante-bellum history are undisputed: 1) It was the secession issue that brought the country to war; 2) not the political mainstream on either side that issue substantively opposed slavery and white supremacy.

The federal government had no intention to abolish slavery during the ante-bellum era, and it was in fact a 45-year period of grossly inequitable tariff policy that eventually alienated the loyalty of Southerners from Washington. When threats against slaveholding emerged, they did not question the legality of the institution where it was practiced, instead, they related to extensions of slavery into new areas from where there was foreseen an impact upon the balance of political power—specifically power over the federal tariff, an imbalance influencing the economic character of the nation far more profoundly than readily apparent from its ostensible source as primary source of federal government revenues.

Although cotton was well known to be grown with slave labor, it was never cultivated by any state that had a stake in the making; on the contrary, it was in fact states that, by sustaining the tariff, Southern protests, ensured that competition for the cotton would always be ineffective to domestic buyers. And it is undeniably clear that the explosive growth of slavery was actually fueled by a demand concentrated in the nation's industrial states. Neither was there an initiative from Washington to free slaves by offering financial compensation to slaveholders. And most telling, the South's efforts to repeal of the hated tariff never brought Northerners a response that envisaged achieving emancipation by means of quid pro quo.

With conventional historians having established that the federal government went to war for the purpose of crusade against slavery, those infernal Southerners are just sure to ask why, when government leap-frogged all the means that might have culminated in an abolition by negotiation, it is inappropriate to conclude that what the leadership of North's great egalitarian society actually did was reveal itself as a collection of mongers.

DENNIS G. SAUNDERS
Columbia, Md.

Perhaps Nelson Winbush's claim that tens of thousands of blacks will be fought for the Confederacy is exaggerated, but whether, as his detractors propose, some or all black Confederate soldiers

Just Serve the Steak And Hold the Sizzle

Your May 22 Money & Investing "More Firms Use Options to Gamble Their Own Stock" was a great example of 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.

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



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, although Duquesne 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 any particular source. Rather, the PSA commits Duquesne to supply the power as scheduled in accordance with the PSA. Duquesne will rely on owned generation or purchase power where appropriate to supply power scheduled under the PSA.

Q3. Would bids which deviate from the bid floor price, length of purchase, or other terms and conditions specified 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 Duquesne's native 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 Agreement attached 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 the intent of the PSA to excuse DLC's non-performance for events of Force Majeure without providing comparable relief 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 interface points: APS, AEP, OE and Centerior?

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

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

(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 2599 MW.

(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 a delivery point.

A9. Duquesne intends to arrange delivery points with the purchaser that are workable given the nature of the transmission service that is procured. For example, if the purchaser seeks delivery of the power off-system using point-to-point service, the purchaser may want to designate particular delivery points as "firm." Duquesne intends to work with the purchaser in

DLCO Request for Proposal Frequently Asked Qu...

arranging delivery points that would accommodate any such needs.

Q10. Under the proposed PSA the buyer is responsible for arranging and paying for transmission required across the DLC system. Will DLC pay liquidated damages to the buyer for financial losses incurred by the buyer which 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 the FERC'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 as follows:

Delivery of Firm Power under this Agreement shall be at a point or points on the Duquesne Transmission System as mutually agreed by the Parties ("Points of Delivery"), provided, however, that in no event shall Duquesne be responsible for the purchase of transmission service on the Duquesne Transmission System to effect such delivery unless otherwise agreed by the Parties. "Duquesne Transmission System" shall mean the transmission facilities owned by 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 third parties 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 deliver such purchased power to the Duquesne system unless the purchaser requests, and Duquesne agrees, that it be delivered 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-market exposure 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 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 Party shall 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 other performance, 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 of not 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 of capacity

DLCO Request for Proposal Frequently Asked Qu...

and/or energy to be delivered as determined in a commercially reasonable manner. Other amounts due between the Parties under the Agreement or any other agreement between the Parties shall be determined in a commercially reasonable manner. Each Party reserves to itself all rights, set offs, counterclaims and other defenses to which it is or may be entitled arising from or out of the Agr

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

Q13. Will DLC amend the PSA to include conditions of Force Majeure that apply equally to Buyer including a provision 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 in the 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 is in Section 4.2 and it applies only to Duquesne because Duquesne is the only party liable under that section for non-delivery penalties.

Q14. Will DLC amend Section II.3 (Triggering Events) of the Security Addendum by replacing "...If at any time during 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 below Standard & Poors BBB..."?

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

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 transmission service.

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.

VOLUME III

Duquesne Statement No. 8

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

**Direct Testimony
of
Fred R. Allison**

Contents:

**Regarding Metering, Meter Reading, Billing, Payment Processing,
Collection and Supplier Settlements.**

DIRECT TESTIMONY OF FRED R. ALLISON

1 **I. Qualifications**

2 Q. Please state your name and business address.

3 A. Fred R. Allison, 411 Seventh Avenue, P.O. Box 1930, Pittsburgh, Pennsylvania 15230-
4 1930.

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

6 A. I am employed by Duquesne Light Company ("the Company" or "Duquesne") as an
7 Assistant Controller in the corporate Controller's Unit.

8 Q. Please describe your educational background.

9 A. I graduated from Pennsylvania State University with a Bachelor of Science degree in
10 Business Administration with a major in Accounting in 1971, and from Ohio State
11 University with a Master of Accounting degree in 1974. In addition, I have completed
12 continuing education programs in accounting and budgeting at the University of
13 Pittsburgh and the University of Wisconsin, Madison, respectively.

14 Q. Do you hold any professional licenses and are you a member of any professional
15 organization?

16 A. I am a Certified Public Accountant (CPA) licensed by the Commonwealth of
17 Pennsylvania and am a member of the American Institute of CPA's.

18 Q. Please describe your employment history.

19 A. Immediately following graduation from Ohio State, I was employed by the accounting
20 firm of Haskins & Sells, now Deloitte & Touche, from 1974 to 1976. Since 1976, I have
21 been employed by Duquesne Light in the following positions: Statistical Accountant -

1 CAPCO, 1976-1978; Manager, Customer Accounting, 1978-1985; Manager, General
2 Accounting, 1985-1988; Manager, Financial Systems, 1988-1991; Manager, Corporate
3 Budgeting, 1991-1996; and the position I now hold, Assistant Controller.

4 Q. Please describe your current responsibilities.

5 A. I oversee the operation of the accounts payable, customer accounting, payroll accounting
6 and valuation & property records departments. In addition, I am managing the business
7 process redesign to implement the Company's Retail Access Pilot Program.

8 Q. Please describe your memberships in any industry organizations.

9 A. I have been a member of various accounting and budgeting committees of the Edison
10 Electric Institute (EEI); the Pennsylvania Electric Association (PEA) and the Central
11 Area Power Coordination Group (CAPCO).

12 Q. Have you previously testified before this or any other regulatory commission?

13 A. I provided testimony in a customer service billing dispute before an administrative law
14 judge of the Pennsylvania Public Utility Commission in the early 1980's.

15 **II. Purpose of Testimony and Conclusions**

16 Q. What is the purpose of your testimony in this proceeding?

17 A. My testimony and accompanying exhibits describe and support the Customer Choice Plan
18 for the implementation of metering, meter reading, billing, payment processing,
19 collections and supplier settlement during the Transition Period. In doing so, I will
20 address the reasons why Duquesne's implementation plan satisfies the requirements of the
21 Restructuring Legislation.

22 My testimony is organized as follows. I first discuss the requirements and
23 objectives of the Restructuring Legislation. I next discuss the manner in which Duquesne

1 will address the implementation issues associated with metering, billing and other
2 revenue cycle services. I next address the arguments of certain stakeholders that revenue
3 cycle services should be unbundled. Finally, I discuss the supplier settlement procedures
4 that Duquesne is proposing.

5 Q. What are your principal conclusions?

6 A. First, I conclude that Duquesne's implementation plan for customer choice will maintain
7 or improve the reliability of service customers enjoy today and will treat customers and
8 competitive suppliers fairly. In particular, I conclude that the new automated metering
9 service being installed by Duquesne, the Customer Advanced Reliability System
10 ("CARS"), which provides time differentiated pricing capability for customers, will
11 enhance the transition to competition by broadening the nature of generation services that
12 customers are able to purchase. Second, I conclude that the unbundling of revenue cycle
13 services is not appropriate at this time and that, even if it were appropriate to do so in the
14 future, the matter should be addressed generically by the Commission in a rulemaking
15 proceeding, not in this case. Third, I conclude that Duquesne's proposal for supplier
16 settlement is appropriate because it uses the best available information and technology in
17 determining whether suppliers' deliveries and customer consumption are in balance.

18 **III. Statutory Requirements**

19 Q. Please describe the requirements of the Restructuring Legislation that apply to metering,
20 billing and other revenue cycle services.

21 A. There are a number of provisions of the Restructuring Legislation that discuss the
22 provision of revenue cycle services. These provisions are largely contained in Section
23 2807. I summarize them briefly below:

- 1 • Section 2807(a) states that an electric distribution company ("EDC"), with
2 Commission approval, "may require that the customer install, at the customer's
3 expense, enhanced metering capability sufficient to match the energy delivered by
4 the electric generation suppliers with consumption by the customer."
- 5 • Section 2807(c) provides that "subject to the right of an end-use customer to
6 choose to receive separate bills from its electric generation supplier, the [EDC]
7 may be responsible for billing customers for all electric services." This section
8 also requires that (i) bills contain unbundled charges, (ii) electric suppliers provide
9 the EDC with certain billing data, and (iii) the EDC be protected from having to
10 remit payment to an electric supplier before having received payment from the
11 customer.
- 12 • Section 2807(d) requires that the EDC "continue to provide customer service
13 functions including meter reading, complaint resolution and collections" and that
14 "customer services shall, at a minimum, be maintained at the same level of quality
15 under retail competition."
- 16 • Section 2804(3) provides that the Commission "shall require the unbundling of
17 customer bills to separate the charges for generation, transmission and
18 distribution" and that "the Commission may require the unbundling of other
19 services."

20 Q. What do you conclude from these requirements?

21 A. In my opinion, these requirements, taken together, demonstrate support for the following
22 three principles. First, maintaining customer service at current levels is a key priority and
23 no policy should be adopted that would degrade service levels. A necessary corollary is

1 that customer service levels should be improved if possible. Second, the Legislation
2 recognizes the potential customer benefits of installing "enhanced metering capability"
3 and therefore authorizes the Commission to order such service. Third, the unbundling of
4 bills and services is contemplated, but the Legislation specifically indicates that the
5 unbundling of generation, transmission and distribution services is the first priority.

6 Q. How do these requirements relate to Duquesne's implementation plan?

7 A. As I will explain in more detail below, Duquesne's implementation plan is fully
8 consistent with the statutory requirements and objectives. First, CARS not only
9 maintains, but increases, the high level of service that Duquesne's customers enjoy today.
10 Second, CARS will provide customers the ability to obtain the full benefits of a
11 competitive generation market by providing them the ability, among other things, to
12 purchase products that are priced on a time-differentiated basis. Third, Duquesne will
13 unbundle customer bills to separate charges for generation, transmission and distribution
14 and will provide customers the option of having their electric supplier submit a separate
15 bill for the services it provides.

16 **IV. Duquesne's Implementation Plan for Revenue Cycle Services**

Metering

17 Q. Please describe Duquesne's plan regarding metering during the Transition Period.

18 A. In January 1996, Duquesne signed a fifteen year, full service contract with Itron, Inc. a
19 leading supplier of energy information and communication solutions to the utility
20 industry to install, operate and maintain CARS. CARS will provide Duquesne with an
21 electronic communications link to its approximately 580,000 customers in Allegheny and
22 Beaver counties. With the new system, customers' use of electricity will be recorded and

1 communicated electronically to a control center in the Company. As a result, customer
2 service personnel will have a much greater insight into the status of power delivery across
3 the system and for individual customers. Customers also will be able to request electric
4 service to start or stop with no advance notice, and service to the location can be stopped
5 or started without visiting the site. Additionally, customers who have electric meters
6 inside their homes will no longer have to provide access to have their meters read.

7 The system's ability to process information about power delivery will provide
8 customers new choices and greater convenience. For example, customers may be able to
9 determine which day of the month to pay their bills. CARS will enable development of a
10 daily profile of the electricity usage of each customer. CARS also will allow customers
11 to obtain the benefits of time differentiated pricing and will facilitate supplier settlements.

12 Customers will benefit from increased energy security. The system will inform
13 the Company when a customer is out of service. Upon detection of an outage, CARS
14 automatically will notify Company personnel so that restoration can begin more quickly.

15 The new system also will enable the Company to track more effectively electric power
16 load growth. With more detailed information about customer demand, the Company can
17 improve its ability to respond to the need for higher capacity distribution equipment. In
18 these ways CARS will add a further tool by which the Company will strengthen its
19 commitment to the highest level of reliability in Pennsylvania. At its current
20 performance level, Duquesne Light provides service that is available to customers 99.99
21 percent of the time, one of the highest levels in the region over the past five years.

22 Q. Are these benefits provided on an integrated basis?

1 A. Yes, in order to achieve the full benefits of this system, customers must be connected to
2 Duquesne through the CARS network so that the advanced metering capabilities provided
3 within the network can be achieved. Tampering, outage detection and interval metering,
4 for example, require network processing in order for the additional customer benefits to
5 be realized. Outage detection capabilities cannot be implemented without use of the head
6 end processor for interpretation of outage and restoration information. A meter separately
7 installed by a third party or supplier would not possess the capability to independently
8 process this information. Consequently, customers utilizing other metering devices
9 would experience a significantly lower level of service than the customers that are
10 connected to the network.

11 Q. Please explain the timetable for the installation of CARS and whether all customers will
12 receive the associated metering equipment?

13 A. Most CARS functions should be operational by January 1, 1999. The CARS network
14 applies to residential and small commercial customers. In addition, using the UTS MV-
15 90 system, most, i.e., as many as 85 percent, commercial and industrial customers should
16 be connected to the network by January 1, 1999.

17 Q. How will Duquesne recover the costs of CARS?

18 A. The Duquesne contract with Itron is a service agreement that requires Itron to acquire,
19 install and maintain the metering and other facilities necessary to support the automated
20 information network. Duquesne will incur no capital costs to implement CARS. The
21 costs of the service agreement for each year and over the fifteen year term are offset by
22 cost reductions associated with base operations, customer choice, improved reliability and

1 enhanced base services. Customers will not be charged a price increase for the improved
2 and enhanced services from CARS.

3 Q. Please describe how Duquesne's metering plan complies with Section 2807 of the
4 Restructuring Legislation.

5 A. CARS meets the objectives and requirements of the legislation in two important respects.
6 First, CARS will allow Duquesne to provide an enhanced level of customer services,
7 rather than simply maintaining the current level of service. Duquesne thus will meet or
8 exceed the requirements of Section 2807(d). Second, customers will have "enhanced
9 metering capability sufficient to match the energy delivered by the electric generation
10 suppliers with consumption by the customer," as contemplated by Section 2807(a) and
11 customers will be required to pay only for those enhanced services that they desire to
12 purchase.

13 Q. Will CARS be utilized during Duquesne's Retail Access Pilot Program, hereinafter,
14 "Retail Pilot?"

15 A. Yes. Duquesne has four objectives for CARS during the Retail Pilot: 1) to complete the
16 installation and acceptance of the system; 2) to use the system to develop load profiles; 3)
17 to gather daily consumption data for customer participants to aid supplier scheduling and
18 settlement; and 4) to further develop consumption data for the computation of premise-
19 specific customer baselines when historical data are not readily available. The lessons
20 learned from metering in the Retail Pilot will reduce the risks of customer complaints,
21 supplier scheduling problems and supplier settlement disputes during the Transition
22 Period.

Meter Reading

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- Q. Please describe Duquesne's plan regarding meter reading during the Transition Period.
- A. Traditionally, utilities have read customer meters monthly on a cyclical basis determined by the utility. Due to the labor intensive nature of the process, costs were high and the typical extent of the service provided was a meter reading at a point in time. With the implementation of CARS, Duquesne has introduced to its customers a technologically advanced system that will allow increases in the frequency, accuracy and timeliness of meter reading at reduced cost. For example, customers may be able to determine which day of the month to have their bills rendered. Most customer meters will be read daily. Meter reading information is planned to be stored in a Customer Data Warehouse which will provide improved security and facilitate limited, controlled access to this information by customers and suppliers. Access to the Customer Data Warehouse may be required to support: 1) customer evaluation of competing products and services from electricity suppliers; 2) separate billing by electricity suppliers for generation charges if selected by their customers, and 3) electricity supplier scheduling based on load profiles of their customers.
- Q. Please describe how Duquesne's meter reading plan complies with Section 2807 of the Restructuring Legislation.
- A. The advanced technology of CARS clearly will allow Duquesne to gather more information about customer behavior than ever before, more accurately and at a lower cost, thereby enhancing the quality of these services and meeting the requirements of Section 2807(d). Properly authorized supplier changes as defined in Section 2807(d) (1)

1 would be activated on dates specified by customers. Finally, the obligation of the EDC to
2 acquire and deliver service would be measured and priced accurately with CARS as
3 required by Section 2807(e) (3).

4 Q. Will Duquesne's Pilot Program provide an opportunity to test the implementation plan
5 with respect to meter reading?

6 A. Yes. Duquesne has three objectives for meter reading during the Retail Pilot: 1.) to use
7 the CARS fixed network and vans to obtain meter readings for calculating monthly
8 customer bills for T & D and generation services and daily customer usage for supplier
9 settlement; 2) to finalize Customer Data Warehouse data design, structure, retention
10 periods and access protocols; and 3) to facilitate planned enhancements in generation
11 billing and supplier settlement processes during the Transition Period.

12 Unbundled Billing

13 Q. Please describe Duquesne's plan regarding unbundled billing during the Transition
14 Period.

15 A. During the Transition Period, Duquesne will provide each customer a single consolidated
16 bill that includes unbundled transmission, distribution, competitive transition charge
17 (CTC), and any other electricity charges, regardless of the identity of the provider of the
18 services, unless the customer chooses to receive a separate bill for electricity from their
19 third party electricity supplier. No customer will receive a traditional "bundled" bill after
20 December 31, 1998. Duquesne will prepare consolidated bills by computing generation
21 charges based on rate schedules provided by the electricity suppliers. Customer bills will
22 be prepared on a monthly basis, based on meter readings obtained from CARS.

1 Traditional cycle meter reading schedules determined by the EDC may be replaced by
2 customer determined reading, billing and payment dates, subject to processing
3 constraints.

4 Electricity suppliers who have large numbers of customers may encourage their
5 customers to receive separate bills. During the Transition Period separate billing of
6 generation charges is the only form of separate billing that will be supported by
7 Duquesne. For those customers who choose to receive a separate bill for generation
8 charges from their electricity supplier, the supplier will issue a bill directly to each
9 customer, the form and content of which will be determined by the suppliers, subject to
10 Commission regulation. Duquesne will make available to each electricity supplier, for its
11 customers, meter reading data and any other billing determinants.

12 The Duquesne consolidated, unbundled bill format has been designed to minimize
13 customer confusion. Exhibits FRA-1A, B and FRA-2A, B show sample bill formats for
14 *residential and commercial* customers. The appearance of these bills is similar to the
15 current bill except it unbundles Duquesne delivery charges into distribution, transmission
16 and CTC components, and clearly separates these EDC charges from competitively-
17 priced generation charges from electricity suppliers. This standard bill format will enable
18 customers to compare prices and services on a uniform basis. Duquesne will provide this
19 consolidated bill in compliance with Chapter 56 regulations and plain language
20 requirements. In addition, a message with the name and telephone number of the
21 electricity supplier also will appear on the bill.

1 Consolidated billing services offered by Duquesne during the Transition Period
2 will be provided based on a contract between each electricity supplier and Duquesne for
3 the terms and conditions of the billing and related services.

4 Q. Please describe how Duquesne's unbundled billing plan complies with Section 2807 of
5 the Restructuring Legislation.

6 A. Consistent with Section 2807(c) of the Restructuring Legislation, Duquesne will be
7 responsible for billing customers for all electric services, consistent with the regulations
8 of the Commission, regardless of the identity of the provider of the services, subject to
9 the right of an end-use customer to choose to receive separate bills from its electric
10 generation supplier. As described above, the single consolidated bill will present
11 transmission, distribution, CTC, and generation charges in a format sufficient to enable
12 customers to determine the basis for these charges. Currently, the Company intends to
13 identify universal service costs separately for ratemaking purposes, but include these
14 costs in the distribution charges on the bill in order to minimize customer confusion.

15 Q. Will Duquesne's Retail Pilot provide information that will be helpful in ensuring a
16 smooth transition to unbundled billing for all customers?

17 A. I believe so. Duquesne has four objectives for unbundled billing during the Retail Pilot:
18 1) to implement successfully a separate generation billing system to compute the
19 generation charges for electricity suppliers based on traditional rate schedules, 2) to
20 develop policies, procedures and protocols for the exchange of information between
21 electricity suppliers and Duquesne to support separate generation billing, payment
22 processing, accounts receivable collection action, supplier scheduling and supplier
23 settlement, 3) to develop effective procedures for addressing customer billing disputes,

1 and 4) to determine customer responses to the metering, meter reading and billing
2 processes as reflected in the customer bill.

3 Customer Payment Processing

4 Q. Please describe Duquesne's plan regarding customer payment processing during the
5 Transition Period.

6 A. For those customers to whom Duquesne renders a single, consolidated bill, Duquesne
7 will process customer payments for electricity suppliers related to the generation charges
8 on the bill. Those customers who have chosen to receive separate bills from electricity
9 suppliers will remit payments for their generation charges directly to their electricity
10 suppliers. Customers will continue to have choice among a variety of payment options
11 provided by Duquesne. Duquesne will process walk-in payments at Company locations,
12 mail-in payments, walk-in payments at authorized payment agency locations, payments
13 by telephone bill paying service and pre-authorized electronic direct debit payments.

14 Duquesne will provide each electricity supplier a standardized daily report of customer
15 payments processed. These data may be transmitted electronically or placed in a
16 Customer Data Warehouse, subject to the information processing capabilities of
17 electricity suppliers. Duquesne will transfer funds to each electricity supplier within a
18 reasonable period of time following receipt and processing to ensure that payments are
19 good funds to Duquesne at the time of transfer. Customer payments that are dishonored
20 for any reason will be excluded from the funds transfer and will be reported to the
21 electricity supplier. Fund transfers between Duquesne and electricity suppliers will be in
22 United States dollars.

1 In the absence of customer direction to the contrary, partial payments will be
2 applied in the following order: (i) first to extinguish Duquesne's receivables, (ii) second
3 to extinguish electricity supplier receivables and finally, (iii) any residual will be applied
4 to Duquesne's receivable balance. Credit balances resulting from overpayments will be
5 carried forward to future bills in the Duquesne receivable balance. This method of
6 applying payments is consistent with Chapter 56 and good business practice.

7 Q. Please describe how Duquesne's customer payment processing plan complies with
8 Section 2807 of the Restructuring Legislation.

9 A. Duquesne's customer payment processing plan affords customers choice among payment
10 options, minimizes customer confusion by focusing on a single payment for all electric
11 services and provides electricity suppliers with the information they need to properly
12 account for and collect, as appropriate, delinquent and unpaid accounts. Duquesne's plan
13 clearly complies with Section 2807(c) (3) regarding forwarding of payments to suppliers.

14 Customer Collection Plan

15 Q. Please describe Duquesne's plan regarding customer collections during the Transition
16 Period.

17 A. Duquesne's collection procedures for customers who receive a single, consolidated bill
18 will operate consistent with Chapter 56 and any Commission final orders from the
19 Maintaining Customer Service and Universal Service and Energy Conservation working
20 groups addressing these procedures. Duquesne will collect any delinquent, unpaid
21 amounts due from customers for transmission, distribution, CTC and any other EDC
22 related charges. Collection services for electricity suppliers to collect delinquent, unpaid

1 generation charges will require separate action by the suppliers, or will require the
2 electricity suppliers to enter into a contract with Duquesne for the terms and conditions of
3 the collection service. Consistent with current practice, Duquesne will assess a late
4 payment charge on any delinquent, unpaid amounts owed to Duquesne. Duquesne will
5 address the needs of low income and payment troubled customers consistent with the
6 Universal Service and Energy Conservation final order(s) including, but not limited to the
7 Customer Assistance Program (CAP) and the Low Income Usage Reduction Program
8 (LIURP). Duquesne recognizes that only the EDC may terminate service for non-
9 payment of bills and will use payment arrangements consistent with this responsibility.
10 Finally, with the implementation of CARS, supplier switching and customer movements
11 within Duquesne's service territory will be processed more efficiently, resulting in more
12 timely and effective collection action.

13 Q. Please describe how Duquesne's customer collection plan complies with Section 2807 of
14 the Restructuring Legislation.

15 A. Duquesne's collection activities during the Transition Period will not only be maintained
16 at the same level of quality as required by Section 2807(d), but will be enhanced through
17 the use of CARS. Additionally, as appropriate, the Customer Data Warehouse may be
18 enhanced to facilitate access to information regarding delinquent customers. These
19 efforts will ensure that Duquesne's collection activities comply with Chapter 56, Sections
20 2803 and 2807, of the Restructuring Legislation and any final orders from the
21 Commission working groups, including the Maintaining Customer Services and
22 Universal Service and Energy Conservation working groups.

1 Q. Do you believe that the Retail Pilot will provide information relevant to implementing
2 customer collections during the Transition Period?

3 A. Yes. Duquesne will evaluate the impact of retail competition on low income and
4 payment troubled customers and develop new, innovative programs as appropriate to
5 meet their needs. Also, Duquesne will evaluate the impact of supplier switching and
6 customer movements on collection policies and procedures.

7 **V. Unbundling And Competition In Revenue Cycle Services**

8 Q. Is Duquesne proposing to unbundle and separately state the rates for revenue cycle
9 services?

10 A. No. The Restructuring Legislation does not require that these services be unbundled or
11 subjected to competition.

12 Q. Are other stakeholders advocating that these services be unbundled and subjected to
13 competition?

14 A. Yes. In the restructuring proceedings of the other Pennsylvania companies, certain
15 stakeholders have argued that revenue cycle services be unbundled and subject to
16 competition. These stakeholders have contended that, by doing so, consumers will save
17 money and receive an enhanced level of service.

18 Q. What is your opinion of this position?

19 A. Based on the arguments of which I am aware, I conclude that these stakeholders have not
20 presented a compelling case in a number of respects. First, these stakeholders have
21 argued that revenue cycle services can be provided at lower cost and a higher level of
22 quality if they are unbundled and opened to competition. This is a factual contention as
23 to which I have seen very little supporting evidence. In fact, as shown in the articles

1 attached hereto as Exhibit FRA-4, the experience in the United Kingdom with respect to
2 the unbundling of metering services provides evidence to the contrary. There, the
3 government opened metering services to competition; however, due in part to the
4 economies of scale in metering and meter reading, new entrants have not been able to
5 provide these services at a competitive price. According to these articles, "the U.K.
6 approach has produced only high costs, little actual competition in providing meter
7 operation, and virtually no real customer choice relative to metering." King Article at 25.

8 Second, the arguments of which I am aware provide scant, if any, discussion of
9 the safeguards that would be necessary to ensure, as the Restructuring Legislation
10 requires, that service levels are not degraded. One must remember that the revenue cycle
11 services are part of an integrated package of customer services. Accurate metering
12 services (including installation, reading, removal, maintenance, procurement and testing)
13 are essential for the success of a new market structure, especially when issues related to
14 safety, reliability and supplier settlement are considered. Metering and metering data also
15 play a critical role in numerous distribution processes such as: providing a safe
16 termination point to the distribution grid for customer connection, preventing energy
17 theft, allowing distribution planning and maintenance and determining billing
18 requirements. The integrity of the metering, billing and customer service processes must
19 be ensured, and there are serious questions whether such integrity can be maintained if
20 these processes are fragmented among various parties. Meter installation, meter reading,
21 billing, payment processing, collection and customer contact, including outage related
22 activities, are not disjointed functions, but rather, interrelated functions that constitute the
23 distribution provider's interface with its customers. Functional unbundling of some or all

1 of these services could degrade existing services to customers. In the energy services
2 marketplace of the future, providers will survive and prosper based on their ability to
3 differentiate their products and services. In 1995, Duquesne was the first electric utility
4 in Pennsylvania to offer to its customers a service guarantee program. This program
5 guarantees timely arrival for scheduled appointments; accurate meter reading and billing;
6 courteous, professional service to customers; and timely processing of new electric
7 service requests. For the year ended December 31, 1996, Duquesne experienced fewer
8 than 1,500 service errors under this program, a rate of less than 0.01 percent.
9 Degradation of these levels of performance is simply unacceptable. While these services
10 potentially could be competitive in the future, numerous standards and protocols relating
11 to safety, reliability, and accuracy will need to be established first in order to protect
12 consumers. In other jurisdictions, this process has led to time-consuming negotiations
13 among a variety of interested parties, and certainly has the potential to delay retail access
14 implementation.

15 Third, the stakeholders advocating unbundling also do not seem to have addressed
16 whether these services would be truly deregulated. It seems as if the proposals are
17 predicated on the assumption that the EDC would remain the supplier of last resort. This
18 is not competition, but rather simply a one-sided plan that allows suppliers to pick and
19 choose customers that are profitable to serve, while ignoring those that are not profitable.

20 The critical question therefore is whether the market will be sufficient to provide all
21 customers these services at the high level of reliability that exists today, assuming that
22 EDCs are treated fairly and have the right, as all other suppliers, to enter or exit the
23 market to provide these services.

1 Fourth, the unbundling proposals do not seem to recognize that the resulting
2 savings for customers would be minimal, if any. The costs associated with metering
3 activities represent a very small portion of the entire bill for an average customer.
4 Therefore, making these services competitive is unlikely to result in significant customer
5 savings. Even if metering were open to competition at the outset of retail access, there
6 would be very little avoided cost for Duquesne in the near-term since most of the
7 metering infrastructure costs are sunk. The calculation of the avoided cost, if any,
8 resulting from an alternate provider for metering services would be difficult, and involve
9 a complex analysis to consider customer class, size, and location, as well as the obligation
10 to provide metering to the remaining customers. Furthermore, if Duquesne were required
11 to provide an "average" avoided cost credit, the potential would exist for suppliers to
12 target low-cost customers, and thereby raise the metering costs for the remaining
13 customers. Also, there are likely to be additional transaction costs associated with
14 allowing third party metering services, which could further reduce the potential savings
15 for customers.

16 Q. If the Commission believes that unbundling should be considered more closely, what do
17 you recommend?

18 A. I recommend that any such examination take place in a generic proceeding involving all
19 the Pennsylvania utilities, not in individual restructuring cases such as this one. In fact,
20 the Commission has begun such an inquiry in Docket No. M-00960890.F009, Request
21 for Comments - Metering, and has indicated that a tentative order may be issued in
22 August 1997.

1 **VI. Supplier Settlement Process**

2 Q. Please define the supplier settlement issue and indicate why it is important to Duquesne.

3 A. "Supplier settlement" has two components: 1) scheduled delivery of service by each
4 electricity supplier to Duquesne's system versus actual delivery by each electricity
5 supplier; and 2) actual delivery by each electricity supplier to its retail generation
6 customers on Duquesne's system versus actual consumption by those retail generation
7 customers. The scope of the supplier settlement process in the following testimony will
8 be limited to the second definition, actual delivery versus actual consumption. This
9 process is important to Duquesne for two reasons: first, scheduled versus actual delivery
10 is traditional in the electric utility industry and is part of the wholesale purchase and sale
11 of energy that has occurred for years. Actual delivery versus actual consumption,
12 however, is unique to retail competition and is therefore new to Duquesne. Second, the
13 process, if not performed accurately, may misstate the total amount of the energy
14 imbalance and/or the amounts to be paid to or collected from electricity suppliers. The
15 supplier settlement process would not be an issue if, without exception, the usage of
16 every customer were to be recorded as the price of that usage changed. However, even
17 with the functions and features of CARS, inevitably, this will not be the case on January
18 1, 1999. On that date, most customer meters will be read daily. CARS provides the
19 flexibility to record actual hourly usage for each customer. During the Transition Period,
20 Duquesne will evaluate the feasibility from an economic and technological perspective of
21 collecting and using actual hourly readings instead of load research. For purposes of
22 explaining the process in the following testimony, prices will be assumed to change on an
23 hourly basis.

1 Q. Please describe Duquesne's supplier settlement plan during the Transition Period.

2 A. Electricity has differing prices at different times of the day and week. Therefore, the
3 question of how hourly loads and their costs should be attributed to individual customers
4 in the absence of hourly readings -- together with how those same loads should be
5 aggregated and charged to multiple electricity suppliers -- provides a good deal of
6 difficulty.

7 Since hourly readings will not be universally available during the Transition
8 Period, Duquesne will use representative customer load shapes based on actual hourly
9 readings from load profile meters and load research. It will be assumed that all customers
10 in a given class or category use electricity in a single pattern. Using representative load
11 shapes to attribute load responsibility is simple conceptually, but in practice the details
12 are complicated and quite important.

13 The supplier settlement process in its simplest form is aimed at determining the
14 amount of load attributable to each customer and thus each retail supplier on an hourly
15 basis, and then reconciling the determinations with actual metered customer load and
16 supplier delivery data as they become available. The process involves the matching of
17 each supplier's hourly delivery of electricity to the estimated hourly consumption of that
18 supplier's customers, and settling the megawatt-hour electricity imbalance. This process
19 requires reconciliation of data from many sources, as well as the necessary time to collect
20 these data. Duquesne's general approach is to derive the supplier obligations based on
21 the best information available given the current technology, and within the constraints of
22 the schedule for implementing retail generation competition. The most accurate method
23 for determining supplier obligations would be to record usage continuously for every

1 customer. However, it would be imprudent for Duquesne to assume this will be possible
2 beginning January 1, 1999.

3 The program will achieve its ends by using representative customer class load
4 shapes, keeping careful records, and reconciling as much as possible with actual meter
5 readings. Duquesne believes this process will produce reasonable results given the use of
6 actual daily meter reads for residential customers and hourly load profile meters on a
7 representative sample of Duquesne's customers:

8 1) Daily consumption available for most customers. To the maximum extent
9 practical, Duquesne will make use of CARS. This system will facilitate the measurement
10 of actual customer usage on a daily basis during the pilot. For any customer for whom
11 CARS is not available, Duquesne will read their meter on a cyclical monthly basis;

12 2) Representative hourly load profiles based on sample metering data.
13 Furthermore, Duquesne plans to use contemporaneous kilowatt-hour readings from
14 existing hourly load profile meters to develop representative load shapes for pilot
15 customers. These special meters are located throughout Duquesne's service territory and
16 provide hourly data for a sample of residential, commercial and industrial customers.

17 The combination of CARS for most customers and a representative sample of
18 contemporaneous hourly load profiles will increase the accuracy of Duquesne's
19 settlement process. The difference between retail supplier deliveries and customer load in
20 every hour will be multiplied by the energy imbalance rates.

21 The basic steps of the supplier settlement process are summarized as follows: 1)
22 Submit schedules to Systems Operations by electricity suppliers. Electricity suppliers

1 will submit informational schedules on a week-ahead basis and submit formal schedules
2 on a day-ahead basis.

3 2) Create representative load profiles for each customer class. Reading the load
4 profile meters for representative customer accounts will provide a sample of hourly
5 kilowatt-hour consumption patterns. These hourly load profiles will be developed for
6 each customer class.

7 3) Read customer meters. This will result in actual daily kilowatt-hour meter
8 readings for customers with CARS functionality, and monthly kilowatt-hour consumption
9 for customers without CARS functionality or when meter reading information cannot be
10 obtained from CARS.

11 4) Estimate customer usage by supplier. Using the estimated load shapes for
12 each customer class, and the meter readings described above, the amount of retail load for
13 each supplier will be estimated as follows:

14 a) Aggregate kilowatt-hour readings by customer class for each supplier

15 For residential customers with CARS functionality, these will be daily kilowatt-
16 hour figures, and for all other customers these will be monthly figures.

17 b) Apply hourly load profiles to each rate class for each supplier

18 The estimated load profile for each rate class will be used to derive the estimated
19 hourly consumption. These hourly kilowatt-hour figures by rate class will be
20 summed for each supplier to determine that supplier's estimated megawatt-hour
21 load obligation.

22 c) Reconcile and adjust estimated hourly consumption to actual hourly system
23 load. The estimated kilowatt-hour amounts by rate class by supplier will be

1 summed and this total compared to the actual system hourly load, as measured by
2 the System Operations Unit. Differences will be allocated based on each
3 supplier's pro rata share of the total to yield an adjusted estimate of each
4 supplier's retail load obligation.

5 5) Calculate imbalance charges for each supplier. Financial settlement is
6 calculated for each supplier by multiplying the difference between supplier deliveries and
7 the adjusted estimates of retail load obligations by the energy imbalance rate in each
8 hour. The energy imbalance rate is based on energy imbalance service. Energy
9 imbalance service is provided by the control area to balance supply and consumption on
10 an hour-by-hour basis. The energy imbalance charges are based on the difference
11 between the megawatt-hours supplied and the megawatt-hours consumed by customers.
12 If the imbalances are in excess of an hourly "deadband" of 1.5% (per the pro forma
13 tariff), the supplier will pay the following rates (i) in off-peak periods, the higher of
14 Duquesne's out-of-pocket costs (plus 10%), or \$50/mWh, and (ii) in on-peak periods, the
15 higher of Duquesne's out-of-pocket costs (plus 10%), or \$100/mWh. These charges
16 provide a reasonable incentive for suppliers to schedule accurately. As Duquesne gains
17 experience with scheduling practices, modification of these charges may be appropriate.

18 Due to the constraints inherent in the collection of meter readings on a billing
19 cycle basis, the supplier settlement process is expected to lag the calendar month by at
20 least thirty days. The settlement process can be accelerated when daily readings are
21 implemented across the distribution system. As discussed above, based on the results of a
22 feasibility study, should hourly meter reading be adopted, supplier settlement will rely
23 less on load research.

1 Q. Does this conclude your testimony?

2 A. Yes.

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DUQUESNE LIGHT COMPANY

P. Customer Service, Education and Conservation Programs

13. In instances in which the end-use customer chooses to receive a single bill from the electric utility for all electric services regardless of generation supplier, provide a proposed billing format. Show how charges will be unbundled to enable customers to determine the basis for each charge. State the procedures which will be employed to receive accurate, timely billing data from other providers in rendering customer bills after restructuring commences. State how the company intends to prevent the improper disclosure or use of sensitive or proprietary customer information, obtained from outside generation suppliers for billing purposes, within the company or to third parties. Indicate how the company will apply partial payments in satisfaction of the unbundled charges. State how customer billing inquiries or complaints will be handled in a timely and effective fashion.

Response:Consolidated Bill Form

Duquesne will provide each customer the choice to receive a single consolidated bill with itemized charges. Its appearance is similar to the current bill except that it unbundles transmission, distribution, competitive transition charge (CTC) and electricity generation charges. The bill form clearly separates the utility delivery charges from the competitively-priced electricity generation charges. A standard bill form will enable customers to compare prices and services on a uniform basis. Duquesne will provide this consolidated bill in compliance with Chapter 56 regulations and plain language requirements. (Exhibits P-13A and P-13B show sample bill forms). In focus group sessions conducted in March 1997, customers who examined the proposed residential consolidated bill form without any prices or charges responded that the proposed itemization of the various charges was helpful in understanding the bill.

Consolidated Billing Service

Duquesne will provide metering services for customers who choose to receive a single consolidated bill. For information purposes Duquesne will provide electricity suppliers monthly kilowatt-hour readings and monthly maximum kilowatt demand readings (if applicable) in accordance with the existing Duquesne meter reading and billing cycles. Duquesne will provide metering services consistent with Chapter 56 regulations, including estimated readings for utility service when actual meter readings cannot be obtained.

Duquesne plans to offer a complete billing service to the suppliers during the Transition Period, i.e., 1999 through 2005. Duquesne will prepare consolidated bills by computing the generation charges based on rate schedules provided by the electricity suppliers. Calculated bill amounts for generation will be forwarded to the electricity

electricity supplier and Duquesne for the terms and conditions of the billing and related services.

Supplier electricity charges will remain confidential, consistent with Duquesne's code of conduct. Customer information regarding load and consumption shall be provided directly to each customer upon request. Duquesne shall not release the following information ("confidential information") to Duquesne's Retail Marketers or any other generation suppliers without the customer's explicit authorization: the price, quantity, type or destination of a regulated service provided to a customer; the customer's billing, payment or credit history for regulated services; or information on a customer's desire to purchase unregulated products or services. If authorized by a customer, Duquesne shall simultaneously make available to all generation suppliers any confidential information Duquesne provides to its Retail Marketers.

Customer Payment Processing

For those customers to whom Duquesne renders a single, consolidated bill, Duquesne will process customer payments for electricity suppliers related to the generation charges on the bill. Customers will continue to have choice among a variety of payment options provided by the Company. Duquesne will process walk-in payments at Company locations, mail-in payments, walk-in payments at authorized payment agency locations, payments by telephone bill paying service and pre-authorized electronic direct debit payments.

In the absence of customer direction to the contrary, partial payments will be applied: (i) first to extinguish Duquesne's receivables; (ii) second to extinguish electricity supplier receivables; and (iii) any residual to be applied to Duquesne's receivable balance. Payments applied to Duquesne's receivables will extinguish the competitive transition charge balance first. Credit balances resulting from overpayments will be carried forward to future bills in the Duquesne receivable balance. This method of applying payments is consistent with Chapter 56 and good business practice.

Duquesne will transfer funds to each electricity supplier within a reasonable period of time following receipt and processing to ensure that payments are good funds to Duquesne at the time of transfer. Customer payments that are dishonored for any reason will be excluded from the funds transfer and will be reported to the electricity suppliers. Fund transfers between Duquesne and electricity suppliers will be in United States dollars. Gross receipts tax on the generation charges of the electricity suppliers will be remitted to the Commonwealth of Pennsylvania by the electricity suppliers.

Customer Billing Inquiries or Complaints

Duquesne will develop new and enhance existing customer information online data displays which will enable service representatives to answer customer inquiries for the transmission and distribution and electricity supplier portions of the bill. The new online data displays will detail the breakdown of bills and payments for both Duquesne and electricity suppliers and will detail all components of the consolidated bill.

Duquesne will provide the supplier's name and telephone number in the message center on the consolidated bill. Any inquiry or dispute related to supplier plans or rates will be referred to the customer's electricity supplier for further explanation.

Duquesne will handle any inquiry or dispute related to the transmission and distribution portions of the bill in compliance with Chapter 56 regulations. Duquesne will notify the supplier when a billing dispute is initiated and will stop all collection activity on the disputed portion of the bill. Duquesne will again notify the supplier when the dispute is resolved and collection activity resumes.



CHOICE
CUSTOMER
123 MAIN ST

EXHIBIT P-13A
RATE (RSP) - Residential Service

Account Number
1000-123-456-001

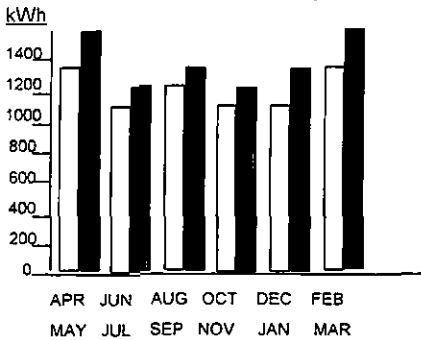
H

Duquesne Light Company Billing Information

Meter Read Information

Present: Mar 1, 19XX - Actual	0500
Prior: Feb 1, 19XX - Actual	0000
Difference	500
Your Meter Multiplier	X 1
Total kWh used	500

Electric Usage Bi-Monthly



■ Prior 12 Months □ Latest 12 Months

Prior Billing Information

Amount Of Last DLCo Bill	\$XX.XX
Payment Received: Feb 15 - Thank You	-XX.XX
Amount Owed From Your Last DLCo Bill	\$X.XX

Current Charges

Customer Distribution Charge	\$X.XX
Competitive Transition Charge - Fixed	X.XX
Transmission Charge	500 kWh @ X.XXX¢ X.XX
Distribution Charge	500 kWh @ X.XXX¢ X.XX
Competitive Transition Charge - Variable	500 kWh @ X.XXX¢ X.XX

Current DLCo Billing Charges

Your Pledge To The Dollar Energy Fund	X.XX
Total DLCo Account Balance	\$XX.XX

Message Center

For questions regarding the Supplier ABC portion of the bill, please call 1-800-555-4567

Your Total Taxes: Around 14.3% of your total bill is for Federal, State and Local taxes.

Supplier ABC Billing Information

Prior Billing Information

Amount Of Last Supplier Bill	\$XX.XX
Payment Received: Feb 15 - Thank You	-XX.XX
Amount Owed From Your Last Supplier Bill	\$X.XX

Current Charges

Usage: 500 kWh From Feb 1 To Mar 1	X.XX
------------------------------------	------

Total Supplier Account Balance	\$XX.XX
---------------------------------------	----------------

Total Amount Due	\$XX.XX
-------------------------	----------------

Estimated Gross Receipts Taxes	Estimated PA State Taxes	Late charge after Mar 20, 19XX	PAYMENT DUE	BUDGET AMOUNT	AMOUNT DUE
\$X.XX	\$X.XX	\$X.XX	Mar 25, 19XX	\$XX.XX or	\$XX.XX

MAKE CHECK PAYABLE TO DUQUESNE LIGHT

Account Number
1000-123-456-001

AMOUNT ENCLOSED	PAYMENT DUE	BUDGET AMOUNT	AMOUNT DUE
	Mar 25, 19XX	\$XX.XX	\$XX.XX

YOU MAY PAY EITHER AMOUNT
Please return this portion with your payment.

CHOICE CUSTOMER
123 MAIN ST
PITTSBURGH PA 15212-0884

Actual Meter
Reading Bill

EXHIBIT P-13B

ACCOUNT NUMBER
2000654321001

SERVICE USED AT: 321 MAIN ST
RATE GS/GMP - GENERAL SERVICE SMALL AND MEDIUM

DATE PREPARED
H SEP 01, 19XX

TYPE OF SERV	SERVICE PERIOD		KILOWATT HOUR INFORMATION					KW DEMAND INFORMATION		
	FROM	TO	METER READINGS		DIFFERENCE	METER CONSTANT	KILOWATT HOURS	DEMAND READING	PWR. FACT. MULT.	BILLING DEMAND
			PRIOR	PRESENT						
P	02-08	03-10	3442	3465	23	480.0	11040	.08	1.00	38.40
L	02-08	03-10	0193	0387	194	12.0	2328	.93		11.20
					TOTAL		13368			49.60

DUQUESNE LIGHT COMPANY BILLING INFORMATION				SUPPLIER ABC BILLING INFORMATION			
AMOUNT OF LAST BILL			\$XXX.X	AMOUNT OF LAST BILL			\$XXX.X
PAYMENT - FEBRUARY 23			XXX.X	PAYMENT - FEBRUARY 23			XXX.X
ACCOUNT BALANCE REMAINING			\$X.X	ACCOUNT BALANCE REMAINING			\$X.X
CUSTOMER DISTRIBUTION CHARGE - BILLING PERIOD (1.00 MO.)			\$X.X	CHARGES FOR 02-08 THRU 03-10			
COMPETITIVE TRANSITION CHARGE - FIXED			XX.X	KWH: 13368 KW: 49.6			XXX.X
DELIVERY CHARGES - DEMAND				PENNSYLVANIA SALES TAX			XX.X
TRANSMISSION CHARGE	5 KW @ NO CHARGE		X	CURRENT BILLING PERIOD AMT			XXX.X
	44.6 KW @ \$X.XX / KW		XX.X	PRESENT ACCOUNT BALANCE			\$XXX.X
DISTRIBUTION CHARGE	5 KW @ NO CHARGE		X				
	44.6 KW @ \$X.XX / KW		XX.X				
COMPETITIVE TRANSITION CHARGE / KW	49.6 KW @ \$X.XX		XX.X				
DELIVERY CHARGES - ENERGY							
DISTRIBUTION CHARGE	550 KWH @ X.XX¢ / KWH		XX.X				
	750 KWH @ X.XX¢ / KWH		XX.X				
	12068 KWH @ X.XX¢ / KWH		XX.X				
COMPETITIVE TRANSITION CHARGE	550 KWH @ X.XX¢ / KWH		XX.X				
	750 KWH @ X.XX¢ / KWH		XX.X				
	12068 KWH @ X.XX¢ / KWH		XX.X				
PENNSYLVANIA SALES TAX			XX.X				
CURRENT BILLING PERIOD AMOUNT			XX.X				
PRESENT DLCO ACCOUNT BALANCE			SXXX.X				
				MESSAGE CENTER			
				FOR QUESTIONS REGARDING THE SUPPLIER ABC OF YOUR BILL, PLEASE CALL 1-800-555-4567.			
				APPROXIMATELY 16.5% OF YOUR BILL IS FOR FEDERAL, STATE AND LOCAL TAXES.			
				TOTAL AMOUNT DUE			
				\$XXXX.X			

EST. PA STATE TAXES	LATE PYMT CHARGE RATE PER MONTH
SXXX.XX	1.25%

PAYMENT DUE	DLCo AMOUNT	SUPPLIER AMT	TOTAL AMT DUE
MAR 28 'XX	XXX.XX	XXX.XX	XXXX.XX

Duquesne Light

One Oxford Centre
301 Grant Street
Pittsburgh, PA 15279-0001

AMOUNT ENCLOSED	PAYMENT DUE	TOTAL AMOUNT DUE
	MAR 28 'XX	XXXX.XX

MAKE CHECK PAYABLE TO DUQUESNE LIGHT

ACCOUNT NUMBER 2000654321001

COMMERCIAL CHOICE CUSTOMER
321 MAIN ST
PITTSBURGH, PA 15212-0084

PLEASE RETURN THIS PORTION
WITH YOUR PAYMENT.

2000654321001 000000000000 000000000000 000000000000

DUQUESNE LIGHT COMPANY

P. Customer Service, Education and Conservation Programs

14. Provide a proposed billing format for customers who choose to be billed separately for energy service by their electric generation provider. Show how charges will be unbundled to enable customers to determine the basis for each charge. State the procedures from other providers (if any) in rendering customer bills after restructuring commences. Indicate how customer billing inquiries or complaints will be handled in a timely and effective fashion.

Response:

Separate Billing

Duquesne will provide each customer the choice to receive a separate bill from their electricity supplier. If a customer chooses separate billing, they will receive two bills: one from Duquesne for charges related to transmission and distribution and one from their electricity supplier for their generation charges.

For those customers who choose to receive a separate bill from their electricity supplier, the supplier will issue a bill directly to the customer, the form and content of which will be determined by the suppliers, subject to Commission regulations.

Duquesne Bill Form

The Duquesne bill form will be the same as for those customers who receive a single bill from Duquesne. The only difference will be that the electricity supplier data will not be included on the bill. (See Exhibit P-14A and P-14B.) A bill message will show that the customer has selected billing from their electricity supplier.

Separate Billing Service

Duquesne will provide metering services for customers who choose to receive a separate bill from the electricity supplier. For bill calculation purposes Duquesne will provide electricity suppliers monthly kilowatt-hour readings and monthly maximum kilowatt demand readings (if applicable) in accordance with the existing Duquesne meter reading and billing cycles. The information will be electronically forwarded to electricity suppliers for their customers on the day after the normal meter reading cycle. Duquesne will provide metering services consistent with the Chapter 56 regulations, including estimated readings for utility service when actual meter readings cannot be obtained.

Customer Payment Processing

Customers who have chosen to receive separate bills from electricity suppliers will remit payments for electricity directly to them.

Customer Billing Inquiries or Complaints

Duquesne will handle any inquiry or dispute related to the transmission, distribution or competitive transition charge (CTC) items of the bill in compliance with Chapter 56 regulations. Customer inquiries or disputes related to the electricity supplier bill will be documented and referred to the electricity supplier for handling.



CHOICE
CUSTOMER
123 MAIN ST

EXHIBIT P-14A
RATE (RSP) - Residential Service

Account Number
1000-123-456-001

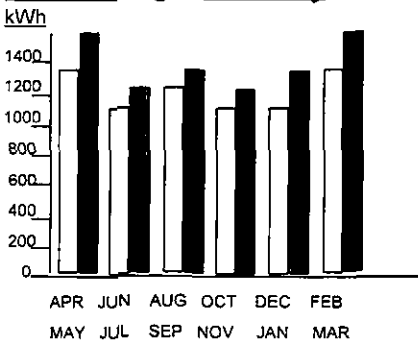
H

Duquesne Light Company Billing Information

Meter Read Information

Present: Mar 1, 19XX - Actual	0500
Prior: Feb 1, 19XX - Actual	0000
Difference	500
Your Meter Multiplier	X 1
Total kWh used	500

Electric Usage Bi-Monthly



■ Prior 12 Months □ Latest 12 Months

Prior Billing Information

Amount Of Last DLCo Bill	\$XX.XX
Payment Received: Feb 15 - Thank You	-XX.XX
Amount Owed From Your Last DLCo Bill	\$X.XX

Current Charges

Customer Distribution Charge	\$X.XX
Competitive Transition Charge - Fixed	X.XX
Transmission Charge	500 kWh @ X.XXX¢ X.XX
Distribution Charge	500 kWh @ X.XXX¢ X.XX
Competitive Transition Charge - Variable	500 kWh @ X.XXX¢ X.XX

Current DLCo Billing Charges

Your Pledge To The Dollar Energy Fund	X.XX
Total DLCo Account Balance	\$XX.XX

Message Center

For questions regarding the Supplier ABC portion of the bill, please call 1-800-555-4567

Your Total Taxes: Around 14.3% of your total bill is for Federal, State and Local taxes.

Supplier ABC Billing Information

OUR RECORDS INDICATE THAT YOU HAVE REQUESTED A SEPARATE BILL FOR YOUR SUPPLIER ENERGY CHARGES.

Estimated Gross Receipts Taxes	Estimated PA State Taxes	Late charge after Mar 20, 19XX	PAYMENT DUE	BUDGET AMOUNT	AMOUNT DUE
\$X.XX	\$X.XX	\$X.XX	Mar 25, 19XX	\$XX.XX or	\$XX.XX

MAKE CHECK PAYABLE TO DUQUESNE LIGHT

Account Number
1000-123-456-001

AMOUNT ENCLOSED	PAYMENT DUE	BUDGET AMOUNT	AMOUNT DUE
	Mar 25, 19XX	\$XX.XX	\$XX.XX

YOU MAY PAY EITHER AMOUNT
Please return this portion with your payment.

CHOICE CUSTOMER
123 MAIN ST
PITTSBURGH PA 15212-0884

Actual Meter
Reading Bill

10001234560011 000000000000 000000000000 000000000000

EXHIBIT P-14B

ACCOUNT NUMBER
2000654321001

SERVICE USED AT: 321 MAIN ST
RATE GS/GMP - GENERAL SERVICE SMALL AND MEDIUM

DATE PREPARED
H SEP 01, 19XX

TYPE OF SERV	SERVICE PERIOD		KILOWATT HOUR INFORMATION				KW DEMAND INFORMATION			
	FROM	TO	METER READINGS		DIFFERENCE	METER CONSTANT	KILOWATT HOURS	DEMAND READING	PWR. FACT. MULT.	BILLING DEMAND
	PRIOR	PRESENT								
P	02-08	03-10	3442	3465	23	480.0	11040	.08	1.00	38.40
L	02-08	03-10	0193	0387	194	12.0	2328	.93		11.20
					TOTAL		13368			49.60

DUQUESNE LIGHT COMPANY BILLING INFORMATION				SUPPLIER ABC BILLING INFORMATION	
AMOUNT OF LAST BILL			\$XXX.X		
PAYMENT - FEBRUARY 23			XXX.X	CR	
ACCOUNT BALANCE REMAINING			\$X.X		
CUSTOMER DISTRIBUTION CHARGE - BILLING PERIOD (1.00 MO.)			\$X.X		OUR RECORDS INDICATE THAT YOU HAVE REQUESTED A SEPARATE BILL FOR YOUR SUPPLIER ENERGY CHARGES. MESSAGE CENTER FOR QUESTIONS REGARDING THE SUPPLIER ABC OF YOUR BILL, PLEASE CALL 1-800-555-4567. APPROXIMATELY 16.5% OF YOUR BILL IS FOR FEDERAL, STATE AND LOCAL TAXES.
COMPETITIVE TRANSITION CHARGE - FIXED			XX.X		
DELIVERY CHARGES - DEMAND					
TRANSMISSION CHARGE	5 KW @ NO CHARGE		X		
	44.6 KW @ \$X.XX / KW		XX.X		
DISTRIBUTION CHARGE	5 KW @ NO CHARGE		X		
	44.6 KW @ \$X.XX / KW		XX.X		
COMPETITIVE TRANSITION CHARGE / KW	49.6 KW @ \$X.XX		XX.X		
DELIVERY CHARGES - ENERGY					
DISTRIBUTION CHARGE	550 KWH @ X.XX¢ / KWH		XX.X		
	750 KWH @ X.XX¢ / KWH		XX.X		
	12068 KWH @ X.XX¢ / KWH		XX.X		
COMPETITIVE TRANSITION CHARGE	550 KWH @ X.XX¢ / KWH		XX.X		
	750 KWH @ X.XX¢ / KWH		XX.X		
	12068 KWH @ X.XX¢ / KWH		XX.X		
PENNSYLVANIA SALES TAX			XX.X		
CURRENT BILLING PERIOD AMOUNT			XX.X		
PRESENT DLCO ACCOUNT BALANCE			\$XXX.X		
				TOTAL AMOUNT DUE:	\$XXXX.X

EST. PA STATE TAXES	LATE PYMT CHARGE RATE PER MONTH
\$XXX.XX	1.25%

PAYMENT DUE	DLCO AMOUNT	SUPPLIER AMT	TOTAL AMT DUE
MAR 28 'XX	XXX.XX	XXX.XX	XXXX.XX

Duquesne Light

One Oxford Centre
301 Grant Street
Pittsburgh, PA 15279-0001

AMOUNT ENCLOSED	PAYMENT DUE	TOTAL AMOUNT DUE
	MAR 28 'XX	XXXX.XX

MAKE CHECK PAYABLE TO DUQUESNE LIGHT

ACCOUNT NUMBER 2000654321001

COMMERCIAL CHOICE CUSTOMER
321 MAIN ST
PITTSBURGH, PA 15212-0084

PLEASE RETURN THIS PORTION
WITH YOUR PAYMENT.

2000654321001 000000000000 000000000000 000000000000

DUQUESNE LIGHT COMPANY

P. Customer Service, Education and Conservation Programs

15. If the utility intends to permit generation suppliers (including its own generation affiliate or division) to bill all charges, provide a proposed billing format. Show how charges will be unbundled to enable customers to determine the basis for each charge. State the procedures which will be employed to transmit accurate, timely billing data to other providers in rendering customer bills after restructuring commences. Indicate how the billing company will apply partial payments in satisfaction of the unbundled charges. State how customer billing inquiries or complaints will be handled in a timely and effective fashion.

Response:

Duquesne will continue to perform essential regulated metering, billing, and other customer related services during the Transition Period. The precise line of demarcation between regulated distribution services and competitive retail services will need to be established. There is a question of whether metering, billing, and certain types of customer services - which are regulated distribution services today - should be deemed to be regulated or competitive services after the Transition Period. Whether these services can and should be provided on a competitive basis at the end of the seven-year Transition Period will depend in part on market developments that may occur during the Transition Period, but are uncertain today.

Duquesne believes that metering, billing and customer services should remain regulated as distribution services until the ability to provide them competitively in a safe and reliable manner has been demonstrated as part of a Commission proceeding. Duquesne recognizes that these services could eventually become competitive. However, during the Transition Period, as the new industry structure evolves, Duquesne believes that the potential costs of allowing metering to be competitive exceed the benefits for the reasons stated in Mr. Allison's testimony.

Therefore, the Company recommends that metering, billing and related services remain regulated until a generic proceeding involving all the Pennsylvania utilities to address further unbundling of these services has been completed.

See the responses to Exhibit FRA-1 and Exhibit FRA-2.

By Chris S. King

Competition at the Meter: Lessons From the U.K.

Metering lies at the heart of electric competition, but may work best as a "natural" monopoly controlled by the distribution utility.

Metering represents one of the more complex issues in retail electric competition—one that suffers from major misperceptions. In fact, most industry participants remain unaware that metering techniques effective enough for competition (hourly reads, daily retrieval) already exist today not only in scale, but also at low cost.

Issues like transmission pricing receive the most attention, but metering will actually have far greater effects on consumers and any successful operation in a competitive retail environment. The United Kingdom learned that lesson in 1994, when it expanded

to competition in 1990. Half-hourly metering of customers, with daily data retrieval, currently forms the standard, because the Electricity Pool of England and Wales ("the Pool") prices power by the half-hour (see Figure 1). In 1998, small commercial and residential consumers will be able to choose their power suppliers. This market of 23 million potential customers will bring the metering issue to the fore.

Back in the United States, the California Public Utilities Commission (CPUC) has called for a system generally similar to that in the United Kingdom: a centralized power pool, an independent

DAWG examined these issues in detail, filing its draft report on August 30, 1996.

Experience gained in the United Kingdom and preliminary work in the DAWG process in California indicates that decisions on metering will affect key aspects of the competitive market, including consumer choice and confidentiality, billing rates and structures, and balancing supply and demand.

Nevertheless, current trends appear to be leading to a market in which meaningful choice is restricted to large customers and consumer protections are eroded. In such a market, economies of scale are diminished and lost.

In 1994, when the U.K. expanded customer choice, over 50 percent of customer bills had to be estimated.

access from retail suppliers to customers with lower load levels and discovered that over 50 percent of customers' bills had to be estimated.

The United Kingdom began opening retail electricity markets

transmission grid operator, a regulated distribution company, and retail choice of energy supplier. To address implementation issues, including metering, the CPUC formed the Direct Access Working Group (DAWG) in April 1996. The

Gauging Consumption: A Key to Choice

In competitive electricity markets, consumers may choose between peak energy, offpeak energy, or something in between, according to the hourly prices set in the wholesale power market by the competitive power pool. Thus, the only way to determine exactly how much of each "type" of electricity consumers use is to meter them in the same way the pool

operates: hourly (in California), or half-hourly (in the United Kingdom).

Marketers may bundle hours to offer a peak/offpeak or weekday/weekend rate, but they need to know how many kilowatt-hours their customers use during each hour so they can settle with the pool. Marketers need to know these quantities daily, so they can settle with energy suppliers daily, just as the pool operates.

However, due to the perceived high cost of half-hourly metering, the United Kingdom plans to

their fellow customers use. Thus, customers lose out on the "triple benefits" of restructuring originally foreseen by the CPUC: cost reduction for any customer that can shift load off peak, deferral of new peaking generation, and more productive use of existing generating plant.

Second, load profiling limits the customer to a choice of *supplier*, eliminating choice of *rates* that reflect time-varying prices in the wholesale power market.

Third, as power marketers cherry pick customers with good

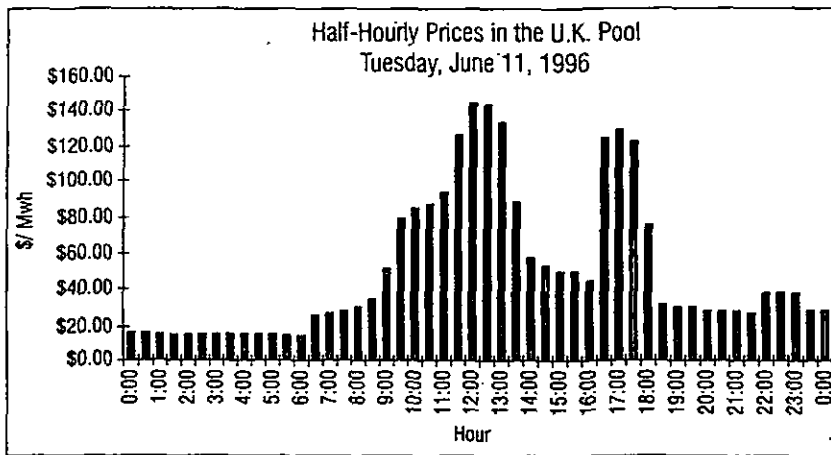
Finally, load profiling eliminates the critical real-time link between supply and demand that will ensure reliability in a competitive electric generation market. Metering enables customers to respond to critical peaks—and their corresponding high prices—by dropping load that obviates the need for brownouts. A five-utility test conducted by the U.K. Electricity Association found that customers reduced peak loads from 20 to 40 percent. One U.K. customer, a steel mill, earned more in 1995 from dropping load during critical peak periods than from its steel business.

Hourly metering is clearly preferable to load profiling, but only as long as it poses no additional or unjustified cost burden.

High Costs?

A Question of Scale

Metering carries three significant economies of scope and scale: size, functionality, and technology. A firm that buys a million meters obtains a lower price than one purchasing 100,000. A meter



meter small commercial and residential customers by class load profile: measuring total consumption and estimating half-hourly usage by assuming an individual customer's load profile is the same as that of all other customers in the class. Relying on old-style, total-consumption meters, the U.K. Pool will use such load profiles to avoid the cost of actual half-hourly metering—but will incur a projected cost of \$480 million for the associated data-processing systems.

In California, meanwhile, the CPUC's Direct Access Working Group has identified several disadvantages to using load profiles.

First, customers do not pay for what they use; they pay for what

Using load profiles to estimate usage will limit customers to a choice among suppliers, denying a choice among rates.

profiles, small commercial and residential customers will be forced into groups with bad load profiles and correspondingly higher prices. Officials in the United Kingdom at the Office of Electricity Regulation (OFFER) admit that the existing and proposed Pool rules enable suppliers to select a group of customers and, based on statistically valid sampling, establish a new load profile for just that group. Marketers will do this, of course, only if the new profile is a better one.

reader reading 500 meters in a consecutive path reads 10 times the number of meters per day as one who reads every 20th meter. A telemetry system for one million meters can provide hourly metering for close to \$1 per meter per month for small users and \$20 per meter per month for the largest users. Since savings for some utilities exceed \$1 per meter per month, telemetry may be available at zero net cost. In contrast, the current system in the United Kingdom, which only supports

20,000 meters, costs \$120 per meter per month for the largest users.

As a multifunctional unit, the meter plays a critical role in eight distribution and customer-service processes:

1) **Safety.** The meter provides a safe, reliable termination to the distribution grid.

2) **Reliability.** Telemetry turns the meter into an outage detection device that communicates critical

meter can be used simply to record consumption, or as an element of a multifunctional system that supports some or all of the functions listed above. The savings realized from the multifunctional system far exceed those from the single-purpose technology.

The technology itself can also achieve significant economies of scale: A network meter-reading (NMR) system can perform advanced processing within the network to record hourly data, for example, or to process outage alarms. Upgrading existing meters instead of replacing them substantially lowers the cost of hourly metering and other functions. Moreover, the cost of the network itself can be shared with other services, such as gas NMR.

At one time, 30 new firms had sought approval in the U.K. as meter operators. . . . Interest dried up by 1996, when economics favored the distribution companies.

Sources

- 1) Office of Electricity Regulation, personal communication, Sept. 3, 1996.
- 2) Office of Electricity Regulation, personal communication, June 6, 1996.
- 3) UK Data Collection Services Ltd., "UKDCS & The UK Electricity Pool," presentation to the California Direct Access Working Group, May 17, 1996.
- 4) The Electricity Pool of England and Wales, "1998 Operational Framework, Business Requirements," March 26, 1996.
- 5) The Electricity Pool of England and Wales, personal communication, June 11, 1996.
- 6) Direct Access Working Group, "Report of the Direct Access Working Group to the California Public Utilities Commission," August 31, 1996.
- 7) The Electricity Association, UK, "Domestic Customer Response to a Multi-Rate Tariff," November 1992.
- 8) Intervenor Comments, Direct Access Working Group Meeting, Sacramento, CA, June 20, 1996.
- 9) The Electricity Pool of England and Wales, "A Blueprint for 1998, Overview of The Electricity Pool's Operational Framework," December 1995.

information about the scope, timing, and frequency of outages, as well as the restoration of power.

3) **Customer Service.** The meter forms the dividing line between equipment the utility is responsible for and equipment the customer is responsible for.

4) **Credit.** The meter is used to connect and disconnect the customer's service for nonpayment, move-in/out, and other reasons.

5) **Energy theft.** A secure meter provides a reliable cash register for the power supplier and the distribution company.

6) **Distribution planning.** Metering data helps to plan the operation, maintenance, and expansion of the distribution grid.

7) **Billing.** The meter records consumption, and may be read manually or remotely.

8) **Prepayment.** In the United Kingdom, about 15 percent of customers use prepayment meters. These meters are programmed to provide a certain amount of power, and then shut off.

These functions all become more efficient when combined at the meter. Among other benefits, the meter permits field employees to perform multiple functions, provides a single entity with numerous operating economies, and distributes training and administrative costs over multiple employee groups.

The third metering economy lies in the scope of the technology. A

Forced Unbundling: An Initial Failure

Who should provide metering services?

In the United Kingdom, OFFER made meter operation (installation, maintenance, and reading) a competitive service. However, few new competitors showed any interest in entering the meter operation market in 1990, when retail access was made available to only 5,000 large customers.

In 1994, when access was extended to approximately 55,000 customers, over 30 entities sought the Pool's approval as meter operators. By 1996, interest had nearly disappeared among all but distribution companies. The combination of technical expertise and scale economies gave the local distribution companies an insurmountable competitive advantage.

The high cost (approximately \$1,600 per year) also discouraged competitors. In addition to the communications costs for radios or phone lines that collect the half-hourly reads daily, there is the cost of amortizing a central data repository across only 25,000 customers.

Although 20 meter operators still exist, the 12 distribution companies provide virtually all customer-site metering services.

Allowing customers to choose meter operators proved a massive initial failure. According to OFFER, customers had no clear incentive to get meters installed properly and on time. For UK Data Collection Services, Inc. (UKDCS)—current manager of the metering data repository—that failure took the form of missing half-hourly data. As a result, over 50 percent of customers' bills had to be estimated. In short, according to UKDCS, the "U.K. competitive market [was] close to chaos."

OFFER and the Pool have now decided to make power marketers responsible for qualifying meter operators in 1998. While customers will theoretically have a choice, the supplier will actually select the meter operator.

Thus, the U.K. approach has produced only high costs, little actual competition in providing meter operation, and virtually no real customer choice relative to metering.

Although California leans toward retaining the regulated distribution company (DisCo) as the meter operator, this approach remains debatable. On the positive side, using the DisCo would offer a number of advantages:

- ▲ Ensure equal and equitable access to low-cost metering for all customers of all classes.

- ▲ Achieve the scale economies associated with network-based approaches to hourly metering. Instead of a total cost of \$10 to \$100 per meter per month for point-to-point, electronic hourly reads with individual meters, the total cost would fall to between \$1.00 and \$2.00 per meter per month.

- ▲ Guarantee data accuracy.

- ▲ Guarantee customer privacy.

- ▲ Guarantee access to the data, as mandated by the CPUC or specified by the customer.

- ▲ Ensure public safety associated with the distribution network.

By 1998, power marketers will take responsibility for certifying meter operators in the U.K.

- ▲ Provide additional scale economies (the DisCo needs access to the meter to fulfill its distribution operations duties), including outage management and restoration, distribution system planning, turn-on/turn-off, line-loss management, and energy-theft identification.

- ▲ Guarantee the requisite expertise in meters and metering systems to select and implement them.

- ▲ Achieve the lowest possible price, since the DisCo can enter into large-scale, long-term contracts through competitive bidding.

- ▲ Keep all these services under regulatory protection.

To be sure, using the DisCo as the meter operator carries with it some important, but surmountable, disadvantages:

- ▲ Customers and power marketers cannot select their meter operator from among competing providers.

- ▲ Changes in metering processes and procedures must be addressed through a sometimes burdensome regulatory process.

- ▲ Without adequate regulatory oversight, meter ownership by the DisCo may provide an unfair competitive advantage to the power-supply side of the utility company.

- ▲ Power marketers would not be able to use metering to differentiate their services (but have greater ability to achieve differentiation through advertising,

traditional marketing, or pricing design).

As it decides whether to unbundle metering services, the CPUC should consider applying the following test, which establishes the

metering part of the natural DisCo monopoly:

Any equipment, facilities, processes, or services used in the distribution of electricity that are shared by or affect multiple customers, and which lead to significant loss of economies of scope or scale when duplicated by multiple firms, should remain within the regulated electric distribution company, unless doing so would inhibit competition in electric supply.

Up to this point, the experience gained in the United Kingdom indicates that the benefits of retaining meter operation within the scope of the regulated distribution company appear to outweigh the perceived advantages obtained from creating a competitive business sector for electric metering services. ▼

Chris S. King is vice president for CellNet Data Systems, Inc. Involved in electric metering issues since 1982, he is active in regulatory proceedings in the United Kingdom, California, New York, and Massachusetts, educating industry participants on the policy, economic, and technical issues of metering. Mr. King has a BS and MS in environmental science from Stanford University and an MS in management science from Stanford's Graduate School of Business.

By Alex Henney

Competition, Confusion, and Chaos:

With no system in place to collect data, retail choice brought gridlock to England and Wales in 1994. California, you're next.

The Metering Muddle

Consider what happens when one moves from dealing with a few thousand sizable customers that are easily identifiable, to more than 20 million residential customers who suddenly acquire the "power to choose."

Congressman Schaefer's bill promises that "by no later than December 15, 2000, all electric utility retail customers shall have the right to purchase retail electric energy services from any person offering to provide those services to such customers." Even more daunting, the California Public Utilities Commission has called for "direct access" open to all sizes of customer, beginning in 1998.

However, as we found out the hard way on the other side of the

thus far—5,000 sites taking over one megawatt were given competitive choice in 1990, then 45,000 sites taking over 100 kilowatts in 1994. We are promised—or perhaps more accurately, threatened—with a free-for-all in 1998, which at the moment looks like chaos for many.

1990-94:

A Shambles

Opening the market in 1990 was not without its problems: shortages of meters and modems

metering and data collection and aggregation, disputes over who owned the data. But since there were relatively few sites, and they included the biggest hitters in the market, and many of the customers had energy engineers who were familiar with the electricity industry and metering and communications, the problems were sorted out fairly quickly. That said, it was only possible to implement competition for customers because there was an agreed-upon market structure. That structure provided three key advantages:

▲ A means of reflecting the time-varying value of electricity in a market-based manner

▲ An accounting and legal framework to ensure that parties consuming electricity paid for it and that those providing it get paid (the Pooling and Settlement Agreement)

▲ A mechanism in the Pool to settle discrepancies between

Competition requires a system for identifying each meter, its characteristics, its operator, its supplier, its line-loss factors, and so on.

Atlantic, these promises are easier to make than to deliver. Competition in England and Wales has been introduced in two phases

connected into the central Pool settlement system, arguments about the price that the distribution companies charged for

power contracted and power consumed. (Such an arrangement avoids penalty payments that distort market behavior by either requiring power retailers to indulge in unnecessary feats of load control or handing an artificial advantage to parties providing a so-called balancing service.)

Simple as these instruments appear, they do not yet appear on the U.S. agenda. Yet, they lie buried like minefields waiting (with attorneys in attendance) for the facile.

Opening access in 1994 was quite another experience: a shambles. Part of the mess was the fault of distribution companies that had not organized themselves properly; part of the mess was due to the electricity regulator's enthusiasm for competition regardless of practicalities. He introduced competitive metering late in the process, without defining the responsibilities of the "meter operator" to ensure that meters were not only on site but connected to a modem that was, in turn, connected to the data aggregation system and the whole setup both commissioned and registered. Competition requires a system for identifying each meter, its characteristics, its operator, its supplier, its line-loss factors, and so on. Introducing such a system becomes far from trivial when tens, if not hundreds, of thousands of meters are involved. Worse, the regulator decided to allow customers lacking a half-hour meter to take competitive supply on load profiles.

In the ensuing chaos, some companies were not billed for six months. The cash flow of the distribution companies suffered severely (the larger ones were \$100 million down for a while) and the problem took two years of intense clerical effort to straighten out. The Pool auditor qualified the Pool's accounts.

1998:

Consider the Reality

So on to 1998, when, in theory, 2 million nonresidential customers and 21 million residential customers will gain competitive choice. The prospect is not merely that of inconveniencing a few thousand commercial customers, but of

example, if the objective really is to create access:

▲ Should customers taking competitive supply be required to have an hour meter (which may be regarded as a transaction-cost barrier to trade), or should they be profiled, which is where the fun and complexity really start?

If we do not trust the incumbent utility to play fair, are we going to unbundle meter operation, data collection, and data aggregation and open them to competitive operation?

making the voters unhappy on a grand scale and incurring the risk of the nightmare scenario of losing the billing systems if there is a mighty mess.

It probably will not happen. This time reality will temper ideological enthusiasms, and distribution companies will not allow themselves to be railroaded into introducing untested systems again. But the bare fact that one can make such an observation at this time, only a year and a half from the date competition is supposed to start, indicates the magnitude of the task at hand.

Consider some of the issues that must be addressed once one moves from dealing with a few thousand or tens of thousands of sizable customers that consume a significant value of power, that are fairly readily identifiable, that are commercially competent, and on which one can afford to spend a reasonable amount of administrative time and effort sorting out their problems on a customized basis. Extending the market to everyone is not only a major systems project, but a move that raises public policy and legal issues, and demands a recasting of the regulatory framework. For

▲ What—if any—measures should be taken to overcome some of the advantages of the incumbent distributor, which has the customer database? Should there be a registration system for states or market areas (if we can define them), with a common meter identification system that is electronically accessible by other parties (are there data privacy issues?) and can be linked into postal information?

▲ If we do not trust the incumbent utility to play fair, are we going to unbundle meter operation, data collection, and data aggregation and open them to competitive operation? If so, how are we going to define the legal relationships between these operations (which have traditionally been part of an integrated utility meter reading, billing, and collection system) and ensure reliable operation?

▲ How are we to define the responsibilities for interfacing with customers as between the transmission provider (WiresCo) and the power retailer. Who does the customer call on the telephone when a power glitch arises? Does the WiresCo have a record of the customer's name, or is that an unfair competitive advantage?

We would have been well advised to proceed incrementally, rather than go for a big bang that may produce a big flop.

The New Hampshire Primary

So far, so good, but

Assisted by some political economists, New Hampshire's retail-access pilot for 17,000 small customers (3 percent of each utility's customer base) appears to be a success so far. There has been some confusion, however, and the PUC chairman agrees that the project was "less than fully baked." The pilot represents a different order of magnitude than the effort undertaken in England and Wales.

The "profile risks" (*i.e.*, the probability of misallocating costs between power retailers) for such a small number and proportion of customers are not financially significant to the players, most of whom have joined in to learn rather than to make money. The conventional NEPOOL settlement arrangement serves adequately for settling "overs" and "unders" because the sums at stake are not large. Access to so few customers is easy to organize of a few DisCos. There is no need to ensure the uniformity of data format between utilities. And data cleanup will be easy.

With string and sealing wax, existing customer-service systems can produce the data for billing the wires charges and for running into programs to aggregate, then to load profile, and then to reconcile with NEPOOL and between the power retailers. The volumes of data are relatively small (although the Public Utilities Commission did have to mandate common protocols and electronic data interchange). And with so few customers, utilities need fear no big rollout problem of perhaps being overwhelmed with customers wanting to change suppliers. While half-baking a small pilot project is manageable, half-baking for millions of customers would create chaos.

This is not to decry the pilot project. Indeed, far from it. We would have been well advised to proceed incrementally, rather than go for a big bang that may be a big flop. Coupled with our experience, the pilot will give the wise the opportunity to measure the problems that have to be faced in opening up the market on a large scale and help them avoid the bear pits.

▲ How are we to define the relationship between a WiresCo and the same utility's power retailing? Will supply to customers that do not seek competitive supply be priced at energy pass-through? Will there be functional unbundling and Chinese walls, or do we suspect them and require at least affiliate unbundling?

▲ How will customers change power retailers? Exactly what flexibility is allowed for contract start date? (Will the computer systems cope?) What provisions will be made for past debt? What happens when husband and wife both sign contracts, or when one power retailer claims that (s)he still has a valid contract and another claims that a new contract is in force?

▲ What, if any, social obligations will be imposed on new entrant power retailers?

▲ What has to be done to convert a relationship between a bundled supply on a tariff that is backed by legislative provisions to a contract based on unbundled supply?

▲ What legal wrinkles lurk in decades of legislation? Perhaps there may be difficulty in disconnecting if a retailer other than the local utility supplies the power.

Before determining the broad parameters of change, shouldn't someone descend from the Olympian heights of political ideology and try to analyze what's in it for the customers, a question that should point up how complex it is worth making the systems. Last, but not least, who is going to lead this grand and complex project and arbitrate the differences of opinion among the stakeholders?

Beyond Public Policy:

Never Pure and Simple

Having resolved the public policy issues, we can start to think about how to design and provide the basic systems infrastructure of registration and settlement (*i.e.*, working out which power retailers owe which generators how much for what power). Then utilities will have to consider the impact on their internal computer systems. How are they going to bill for use of transmission and use of distribution? What changes will have to be made to the main billing system to accommodate the flexibility of presentation that customers will not merely want, but will demand? And last, but definitely not least, consider how to try out the system with real people. Which publicly minded utility is going to volunteer part of its service territory for a pilot so that others can come in and go at its customers and the media can berate it for any system messes? How are we going to roll the show out in a manner that will ensure that utility systems and staff can cope with the possible level of early switchers? (In the gas trial in England—which opened access to a half-million residential customers in April—30,000 households wanted to switch on the first day, overloading the capability of British Gas. The rate of switching has now settled to 2,000 per week, which is manageable.)

Thus far I have only talked about the mechanics: How will utilities and/or others organize the power-retailing function, develop the new systems that will be required—*e.g.*, pricing, risk management, contract management, forecasting and business planning, accounts reconciliation—and determine their policies?

As Oscar Wilde once observed, "The truth is rarely pure and never

simple." I have said enough to indicate why we are having difficulties. There has been no attempt to analyze customer benefits and possible behavior. Although industries do on occasion implement joint projects, they only do so when they share a common interest, something completely lacking in this venture. Commercial politics and distrust among the players is rife. The interests of the generators are not the same as those of the distributors, and the latter differ among themselves. Not one key program date has yet been met. Indeed, it took a year to get an agreed program toward which the distribution companies and

regulator are working. The regulator—really the only person capable of leading the show—has tried to distance himself from responsibility, while berating the industry for not getting an act together. No one knows how much the changes will cost, but few would dispute that it will make change out of a half-billion, and could cost as much as a billion. We will never know.

Given the American ability to generate so much heat and so little light out of the PoolCo versus bilateral trading debate, the forthcoming discussion about access for all promises at least an equal outpouring of ill-informed nonsense and corporate wheel spinning.

The change will be paradise where consultants with imagination but no practical experience will peddle snake oil, and attorneys (as always) will pass Go. ▼

Alex Henney, a former director of London Electricity, was involved in the privatization of the electricity supply industry in England and Wales. He has advised electric companies, governments, and regulators in a number of countries, increasingly the United States and Canada. Mr. Henney recently formed Competitive Electric Strategies, Inc. with Resource Dynamics Corp. of Vienna, VA.

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**PA PUBLIC UTILITY COMMISSION
PROTHONOTARY'S OFFICE**

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DOCUMENT
FOLDER**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

**APPLICATION FOR APPROVAL OF
RESTRUCTURING PLAN UNDER SECTION 2806
OF THE PUBLIC UTILITY CODE**

**Direct Testimony of : Mark G. Karl
Ralph L. Nelson
Ralph E. Duckworth, Jr.
Jeff D. Makholm
Thomas S. LaGuardia**

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VOLUME IV

Duquesne Statement No. 9

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

**Direct Testimony
of
Mark G. Karl**

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DIRECT TESTIMONY OF MARK G. KARL

I. Qualifications:

1

2 Q. Please state your name and address.

3 A. My name is Mark G. Karl. My business address is 411 Seventh Avenue, P.O. Box 1930,
4 Pittsburgh, Pa. 15230 -1930.

5

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

7 A. I am employed by Duquesne Light Company as a Senior Consultant, and I am responsible for
8 managing Duquesne's Integrated Resource Planning Department.

9

10 Q. Please state your educational qualifications.

11 A. I graduated from the University of Pittsburgh with a Bachelor of Science Degree in Mechanical
12 Engineering with an option in Aerospace Engineering. In addition, I earned a Masters Degree in
13 Business Administration (MBA) from the University of Pittsburgh Katz Graduate School of
14 Business, where I majored in General Management with emphasis on Finance. I am a registered
15 Professional Engineer in the Commonwealth of Pennsylvania.

16

17 Q. Please describe your professional experience.

18 A. I have more than fifteen years of diverse experience at Duquesne Light Company. I have worked
19 professionally in a variety of assignments and functional areas within Duquesne, including both
20 fossil and nuclear engineering; corporate and strategic planning; economic analysis; wholesale
21 power marketing; and integrated resource planning. In support of the development of
22 Duquesne's integrated resource plan, and as part of my benchmarking analysis of Duquesne's
23 strategic business units, I have performed numerous economic analyses of Duquesne's

1 generating facilities. As part of the development of wholesale sales proposals, I have developed
2 projections of operating cost and performance for new and/or refurbished generating facilities,
3 both internal and external to Duquesne's current franchise territory. I was involved in the initial
4 physical condition assessment of the Phillips Power Station in support of Duquesne's efforts to
5 sell long term power to General Public Utilities (GPU), and I was Project Manager for the
6 assessment and reactivation project at the Brunot Island Power Station, also in support of the
7 GPU sale. Prior to my employment at Duquesne, I was employed for two years by the Space
8 Systems Division of Rockwell International Corporation as a systems engineer/ analyst working
9 on space shuttle flight control system software.

10
11 Q. What are your current responsibilities?

12 A. I manage and participate in the development of Duquesne's integrated resource plan. I direct the
13 development and submittal of regulatory filings regarding integrated resource planning and assist
14 in representation of Duquesne interests in regulatory proceedings concerning integrated resource
15 planning and related issues. I direct the performance of production cost and preliminary financial
16 analyses concerning proposals and projects involving power generation assets, and I participate
17 extensively in the development and analysis of Duquesne's sales initiatives in the wholesale
18 power marketplace, from the sale of power up to and including the sale of assets such as the Fort
19 Martin Power Station.

20
21 **II. Purpose of Testimony**

22
23 Q. What is the purpose of your testimony?

24 A. My testimony serves three main purposes:

- 25 a) I support the use of Duquesne's hourly marginal cost curve as a known and
26 measurable surrogate for the true market price duration curve which, together with the
27 bid prices from Duquesne's recent power sale solicitation, yields hourly market
28 prices. These hourly market prices are used in my production cost analysis for the

1 period 1999 through 2005 (“Transition Period”), and are used by Mr. Lahtinen to
2 calculate competitive transition charges (“CTC”).

3 b) I support the forecast of production costs and generation output of Duquesne’s units
4 under the Integrated Resource Plan least cost planning scenario, which was provided
5 as input to Mr. Clayton’s generation cost of service analysis for the period 1999
6 through 2005.

7 c) I support the forecast of production costs and generation output, by unit, for the
8 period 2006 through end of unit life, which was provided to Mr. Clayton as input to
9 his estimation of the market value of each of Duquesne’s units at year end 2005.

10
11 **III. Introduction**

12
13 Q. Please describe the Integrated Resource Planning process used at Duquesne.

14 A. The resource planning process begins with the development of a 20 year load forecast. This
15 forecast is the product of a regional econometric model, which predicts future electric demand
16 and energy requirements as a function of economic performance within the market region. The
17 resulting electric forecast is weather normalized, to eliminate year to year variations in demand
18 resulting from changes in the weather. The electric forecast is then compared to Duquesne’s
19 current expected generating and load management capacity, and future resource requirements are
20 quantified as the difference between actual resources and expected demand. The next step in the
21 process is to conduct a technology screening study, to identify viable supply and demand
22 technologies to fulfill future resource requirements. Viable technologies are then assembled into
23 various alternative resource scenarios.

1 Each scenario is analyzed using the PROMOD production cost analysis computer program.
2 PROMOD has been developed by Electronic Data Systems Corp., for use in the prediction of
3 electric utility production costs, and has been reviewed and accepted for this use by the
4 Pennsylvania Public Utilities Commission ("Commission"). The production costs generated by
5 PROMOD for each resource scenario are then entered into a corporate finance model, which uses
6 the production costs and capital requirements of each scenario to generate an annual revenue
7 requirement prediction. The chosen scenario is the scenario with the lowest twenty year net
8 present value revenue requirement. In the past, this lowest net present value plan was referred to
9 as the least cost plan, and the methodology was referred to as least cost planning. With the
10 inclusion of both demand and supply side resource options, the name of the planning process has
11 been changed to integrated resource planning.

12
13 Q. Please describe the function of the PROMOD computer program.

14 A. A description of the function and operation of the PROMOD production cost analysis program is
15 contained in Exhibit MGK-1.

16
17 Q. For how many years into the future does Duquesne plan?

18 A. Consistent with the requirements of the Commission, Duquesne's resource plan extends for a
19 twenty year planning horizon.

20
21 Q. Are these resource plans submitted to any regulatory commission?

22 A. On a yearly basis, every electric utility in the state, including Duquesne, must submit an annual
23 resource plan to the Commission. These annual plans detail each utility's expected load for the
24 next twenty years, and detail the means by which the utility plans to serve load in its service
25 territory.

26
27 Q. How are the resource plans reported to the Commission?

1 A. State of Pennsylvania, 52 Pa. Code §§ 57.141-57.154, which governs the electric utility planning
2 process, includes specific requirements regarding the reporting of resource plans to the
3 Commission and to the public. In accordance with these requirements, Duquesne prepares and
4 submits an annual report which consists of three main parts: 1) an Executive Summary which
5 summarizes the report and its conclusions; 2) the Annual Resource Plan, which details the
6 selected plan, the alternate plans, the load forecast, and all relevant assumptions; and 3) the
7 Report Appendix, which includes supporting information and detailed information tables in a
8 prescribed format and aids the Commission in preparation of a summary report to the State
9 Governor. The informational tables in the Report Appendix are submitted to the Commission in
10 electronic spreadsheet form as well as on paper hard copy. Copies of the Integrated Resource
11 Plan are required to be submitted on or before May 1, to the Secretary of the Commission, the
12 Office of Consumer Advocate, the Pennsylvania Energy Office, and the Office of Small Business
13 Advocate. Informational copies are also submitted to the personnel of other State Bureaus and
14 Offices, and to other utilities in the State. In addition, as a public record, the report is available
15 to consumers and interested parties upon request.

16
17 Q. What is the purpose of these least cost plans?

18 A. The purpose of these integrated resource plans is to ensure that electric utilities reliably provide
19 electric service to all customers within the franchised service territory at the lowest possible cost.

20
21 Q. What is the difference between the analysis traditionally performed for Duquesne's Annual
22 Resource Plan and the analysis you are presenting here?

23 A. The traditional annual resource plan analysis assumes Duquesne operates indefinitely as an
24 integrated utility, with a traditional obligation to supply bundled service, including generation, to
25 any party requesting service within the utility's franchised territory. The focus of a resource plan
26 within this environment is to predict future customer requirements, and to build or acquire
27 appropriate generation resources which meet customer needs at the lowest reasonable cost.

1 Future revenues for the utility would be set by the revenue requirement of the utility system
2 throughout the planning period.

3
4 With the onset of competition in Pennsylvania, utilities will no longer be in a position to operate
5 in the manner described above, but rather will operate as "price takers." Operating as a price
6 taker seeking to maximize profit, Duquesne will operate its generation resources until the
7 marginal cost of operation of these resources equals the prevailing market price. This prevailing
8 market price will vary hourly, and will be set by the marginal operating cost of the last unit
9 dispatched to serve load within the market region.

10
11 As a price taker, Duquesne's generation will effectively be decoupled from customer demand
12 within its existing service territory, since it is assumed Duquesne can always buy or sell at the
13 prevailing market price. Duquesne's units will therefore be dispatched to meet the market price.
14 If the market is able to meet Duquesne's incremental load requirement at a lower cost than
15 Duquesne's next available resource, Duquesne will buy at the market price. Conversely, if
16 Duquesne's resources can produce at a marginal cost less than the prevailing market price, these
17 resources will be dispatched to their full availability or to the point where their marginal cost
18 equals marginal revenue, independent of Duquesne's local requirements.

19
20 The analysis I am presenting here will predict future generation output and operating cost for
21 each of Duquesne's units in that competitive price taker mode rather than in the traditional utility
22 obligation to serve mode of operation. Duquesne's Integrated Resource Plan provides the
23 starting point for this analysis. All of the input assumptions, such as fuel prices and unit
24 availability, as well as any operating constraints used in Duquesne's most recent Integrated
25 Resource Plan will be used here. The analysis will be divided into two parts, corresponding to:
26 (1) operation during the Transition Period (1999-2005); and (2) operation of Duquesne's units
27 after the transition to competition is complete through the end of life of each generating unit.

1 This analysis will therefore provide an estimate of the generating cost and output of each of
2 Duquesne's units, operating as a price taker, over the remaining life of the unit.

3
4 The generation cost and output during the Transition Period are inputs to Mr. Clayton's cost of
5 service analysis used to calculate an ending book value for generation at year end 2005. The
6 generation cost and output beyond 2005 through the end of unit life are inputs to Mr. Clayton's
7 margin analysis used to compare an estimated market value to book value as of December 31,
8 2005.

9
10 Q. How will this PROMOD analysis of generation output and operating cost be performed during
11 the Transition Period ?

12 A. As described in the testimony of Mr. Irvin, Duquesne has recently completed the bidding process
13 for two forward market sales of electricity: a one-year sale and an eight-year sale. Prices
14 revealed in the eight-year sale are used to set the price level at which Duquesne's units are
15 dispatched in this PROMOD analysis. Since the price of electricity varies hourly as a function of
16 regional load, the annual sale price for each year of the Transition Period is mapped into a set of
17 hourly prices using a price duration curve. This hourly representation of the market, for each
18 year of the Transition Period, is then entered into Duquesne's PROMOD model as an exchange
19 transaction. By this I mean that the market is treated as both a buying and a selling opportunity
20 for Duquesne.

21
22 For each hour of the analysis, PROMOD will dispatch Duquesne's generating resources on a
23 lowest incremental cost basis until either Duquesne's service area load is met or the marginal
24 cost of generation equals the hourly market price. If Duquesne's generation is able to meet the
25 system load requirement at an hourly price less than the market price, PROMOD will continue to
26 dispatch units and sell into the market until either Duquesne exhausts its available resources or
27 the marginal cost equals marginal revenue. Conversely, if the PROMOD dispatch reaches the
28 market price before meeting Duquesne's service area load, the remaining load will be met

1 through a purchase from the market and Duquesne's generation whose marginal cost exceeds the
2 market price will stand idle.

3
4 Whether Duquesne will be serving all the customers in its service territory as a generation
5 supplier is not material as it is assumed there will always be buyers or sellers at the prevailing
6 market price. This function of the market effectively decouples Duquesne's generation from
7 service territory load. This analysis will continue for each hour of the Transition Period.
8 PROMOD will accumulate, on a generating unit basis, hourly generation and operating cost.
9 This data is input into Mr. Clayton's generation cost of service analysis. This process will be
10 described in more detail later in my testimony.

11
12 Q. Why use PROMOD for this analysis? Wouldn't it be simpler and more direct to just model the
13 Duquesne system on an hourly basis using a computerized spreadsheet?

14 A. A spreadsheet model could be constructed for each of Duquesne's units which would simply
15 compare, on an hourly basis, the incremental operating cost of the unit to the market price. This
16 model could then decide whether or not the unit should operate for that hour and would
17 accumulate revenue and costs accordingly. The problem is that such a model ignores a number
18 of real-world operating requirements and constraints that PROMOD is equipped to address. For
19 example, while the economics of the marketplace may dictate that a particular unit may run for
20 one or two hours then shut down, units are not operated this way in the real world. Most units
21 have minimum run times and minimum off times, costs are not linear with output, and unit
22 output is not continuously variable. In order to minimize operating costs, a system operator may
23 choose to increase load at an operating unit even though the incremental cost of power at that
24 unit is higher than the first load block of a shutdown unit, if the power is only needed for a
25 transient peak. The operator chooses to pay a higher marginal cost for a short period rather than
26 incur the startup and shutdown costs of another unit. Much of the relative complexity of
27 PROMOD is due to these issues.

28

1 Q. An annual resource plan normally details any capacity additions planned by the utility to meet
2 future load requirements. What is Duquesne proposing in this regard?

3 A. During the transition to competition, Duquesne will maintain reserve generation sufficient to
4 serve generation customers within the franchised service territory. Duquesne will ensure
5 customers enjoy traditionally high levels of service reliability by effectively maintaining a 12%
6 generation reserve, through either direct operation of existing units or through purchase of
7 capacity as required. This level of reserves provides a margin over and above the required 6%
8 ECAR operating reserve requirement, and is also above the 8% reserve identified by ECAR in its
9 August 1996 "Assessment of ECAR-Wide Capacity Margins" as the reserve necessary to meet
10 the ECAR DSCR reliability criterion of 1-to-10 days per year through 2005. The actual amount
11 of firm capacity purchases required to maintain a 12% reserve will depend on the number of
12 customers leaving Duquesne as a generation supplier (and the expected percentage of those
13 customers who will return). If, for example, slightly more than 9% of Duquesne's customers
14 exercise choice by 2004, Duquesne's remaining customers would enjoy a 12% reserve without
15 any purchased capacity.

16

17 Q. How will reserve margins be dealt with in the future?

18 A. The planning reserve is an artifact of vertically integrated utilities which traditionally provided
19 bundled service. A traditional utility would forecast future requirements, and would build
20 capacity to meet those needs. In a competitive environment, capacity needs will be met through
21 choices which arise from free market forces. It would be imprudent of Duquesne to construct
22 new assets to meet a planning reserve requirement, on the expectation that all customers will
23 remain with Duquesne. Accordingly, during the Transition Period, when it appears that
24 Duquesne will fall below the targeted 12% reserve, firm capacity will be purchased at market
25 prices to achieve this target reserve level.

26

27 Q. Does this mean that Duquesne is not planning to build any new generation facilities at any time
28 in the future?

1 A. At present, Duquesne does not have any plans to construct additional generating facilities. This
2 does not mean, however, that Duquesne or a Duquesne affiliate or successor would not construct
3 new facilities. Any newly constructed facility would have to be profitable at prevailing market
4 prices. If prevailing market prices rise to the point where Duquesne, an affiliate, or a successor
5 believes a facility could be constructed which would be profitable at the market price, then such a
6 facility might be constructed. The decision process would be comparable to similar decisions
7 made every day by companies operating in a free market.
8

9 Q. Duquesne's generating units have operating lives which extend beyond the end of the Transition
10 Period. How are the generation, operating cost, market revenue and net margin calculated
11 through end of unit life?

12 A. Post-2005, the analysis of generation, revenue, and cost, is performed on an annual rather than an
13 hourly basis. It is conservatively assumed that since Duquesne's generating assets are primarily
14 baseload facilities, they will be operated at any time they are available to be operated. The
15 annual operating capacity of each of Duquesne's generating units, post 2005, is therefore
16 assumed to be equal to its equivalent availability. The annual revenue from each generating unit
17 is assumed to equal its generation output (calculated at a capacity factor equal to annual
18 equivalent availability) times the annual market prices provided by Mr. Schnitzer. Annual
19 operating cost and output for each unit is obtained from PROMOD programmed to dispatch units
20 at equivalent availability.
21

22 Q. Why do you use an hourly model for the margin analysis during the Transition Period while
23 changing to an annual analysis after the Transition Period has ended?

24 A. There are several reasons for changing from an hourly to an annual analysis. During the
25 transition, market prices are essentially set by the marginal cost of excess generating capacity.
26 As a result, prevailing market prices during many hours of the year are below the operating cost
27 of many existing units. As Mr. Schnitzer explains in his testimony, he has made the
28 "conservative" assumption that the cost of new entry will establish a ceiling price for electricity

1 by the end of the Transition Period. To be consistent with this assumption, we have assumed that
2 all Duquesne's base load facilities will actually be dispatched at any time they are available post
3 2005. These assumptions are conservative in the sense that they will likely overstate the market
4 value of Duquesne's generation for purposes of estimating stranded costs as of 2005.

5
6 Because the existing units will operate whenever they are available, it is reasonable to use an
7 annual capacity factor with an average load weighted price to calculate annual revenue. An
8 hourly analysis beyond 2005 would require the derivation of a new price duration curve, and
9 since the derivation of such a curve would be highly speculative, it was decided that an annual
10 analysis would be sufficiently accurate.

11 12 **IV. Variable Operating Costs and Availability**

13
14 Q. What are the key input assumptions used in your calculation of variable operating and production
15 costs?

16 A. The key input assumptions include fuel costs, variable operating and maintenance costs (O&M),
17 and unit availability which is a function of both *planned and scheduled outages*. Also required
18 are fuel escalation rates and unit operational data such as heat rates, minimum loads, on and off
19 time requirements, dispatch blocks, and any specific unit operating constraints.

20
21 Q. What is the source of your fossil fuel price projections and what prices are used in your analysis?

22 A. Fossil fuel prices and projected escalation used in this analysis were obtained from the Duquesne
23 Fossil Fuel Department. Wherever possible the unit fuel prices used are derived from actual fuel
24 contracts with fuel suppliers, with spot price forecasts and forecasts of prices beyond contract
25 limits obtained from Energy Ventures Analysis (EVA), Resource Data International (RDI), and
26 Wharton Econometric Forecasters (WEFA). These forecasts are blended according to the
27 judgment of the Fossil Fuel Department and are then submitted for use in production cost
28 analyses. The Fossil Fuel Department is also responsible for developing forecasts of emission

1 credit prices which are treated as a variable fuel related cost in the unit dispatch. Projected sulfur
2 credit prices are also obtained from EVA. The forecasts used in the preparation of this analysis
3 are set forth in Exhibit MGK-2.
4

5 Q. What is the source of your nuclear fuel price projections and what prices are used in your
6 analysis?

7 A. Nuclear fuel prices and projected escalation used in this analysis were obtained from the
8 Duquesne Nuclear Fuel Department. Wherever possible the unit fuel prices used are derived
9 from actual fuel contracts with fuel suppliers, with forecasts of prices beyond contract limits
10 obtained from Energy Resources International, Inc. The forecasts used in the preparation of this
11 analysis are set forth in Exhibit MGK-3.
12

13 Q. What is the source of your annual inflation projection?

14 A. The annual inflation projection is used to escalate all non-fuel costs, such as variable O&M, used
15 in the analysis. These projections of annual Gross National Product Implicit Price Deflator were
16 obtained from Wharton Econometric Forecasters (WEFA) and are presented in Exhibit MGK-4.
17

18 Q. What is the source of the unit availability data used in your analysis?

19 A. The unit availability data is based upon the most recent five year actual outage data. The forced
20 outage rate input into PROMOD is the five year average unit equivalent forced outage rate.
21 Scheduled maintenance outages are obtained from the latest actual unit outage schedule
22 maintained by the Duquesne System Operations Department. Beyond the horizon of that actual
23 schedule, PROMOD uses an automatic maintenance schedule generation routine, which
24 replicates the outage frequency used in the actual schedule. The forced and scheduled outage
25 data used in this analysis are presented in Exhibit MGK-5.
26

27 Q. What is the source of the unit Operating and Maintenance budget data and unit operating and
28 performance characteristics used in your analysis?

1 A. Unit O&M data is obtained from the Fossil and Nuclear Generation departments. The operating
2 and performance characteristics of each unit are obtained from the Duquesne Fossil Generation,
3 Nuclear Generation, and System Operations departments as appropriate. The data reflect real
4 world operating limitations used in the operation of Duquesne's system, and in the case of
5 performance data, are the result of operational testing and record keeping. The unit O&M data
6 and unit summary performance data are discussed in the testimony of Mr. Nelson and Mr.
7 Duckworth for the fossil fueled and the nuclear units respectively.

8
9 Q. Previously you stated that your analysis of Duquesne's generating units extends through the life
10 of the each unit. How are these unit lives set?

11 A. For the purposes of this analysis unit retirement dates are set at the end of each units' financial
12 book life. These unit retirement dates are presented in Exhibit MGK-6.

13
14 **V. Price Duration Curve and Calculation of Generation Cost and Output During**
15 **the Transition Period**

16
17 Q. Given the production cost input data presented in the previous section, what other input data is
18 required for this analysis of unit generation and operating cost?

19 A. The production cost data input into PROMOD allows the program to calculate production cost at
20 any level of output. The level of output from each unit is a function of its operating cost as
21 compared to hourly market prices. Therefore, the key input is the hourly market price for each
22 hour of the transition period.

23
24 Q. How is this hourly market price determined?

25 A. The basis for determination of market prices is the forward sale resulting from Duquesne's RFP
26 as described in the testimony of Mr. Schnitzer. Mr. Schnitzer has derived an annual all-hours
27 spot price for each year of the Transition Period from the forward sale data. The resulting single

1 annual all-hours price is mapped into an expected hourly market price using a price duration
2 curve or price shape for each year of the Transition Period.

3
4 Q. Describe what is meant by a price duration curve or price shape.

5 A. The price shape defines the relationship of the market price in any given hour to the all-hours
6 average price for the entire year. For this analysis the price shape is expressed as a series of
7 hourly percentages, with each percentage representing an hourly price as a percentage of average
8 price. For example, if the price shape value for noon on January 15 is 52% with a yearly average
9 price of \$20/MWh, the predicted market price for this hour of this day would be \$10.4/MWh. If
10 the price shape value for noon on June 15 is 128%, the predicted market price would be
11 \$25.6/MWh. The price shape is a simple way of expressing the normal hourly, daily, and
12 seasonal variation in the market price of power.

13
14 Q. What is the source of Duquesne's price shape?

15 A. For this analysis, the price shape is derived from Duquesne's 1996 measured hourly lambda,
16 which is simply the marginal cost of generation on an hourly basis. This choice is consistent
17 with economic theory which holds that the market will clear at the price where marginal revenue
18 equals marginal cost. Since Duquesne is already selling available generation into the wholesale
19 market whenever generation is available at a cost equal to or below the market price, it is
20 expected that Duquesne's hourly lambda should track market prices fairly closely..

21
22 Q. Is the same price shape used throughout this analysis or are different shapes used for different
23 years?

24 A. This analysis uses the 1996 price shape for all years of the Transition Period. Although, the price
25 shape will likely change over time as the current excess of capacity in ECAR comes back into
26 balance, forecasting the demand and supply trends would require speculation. Duquesne,
27 therefore, will rely on existing data.

28 Q. Is there any other use made of the 1996 price shape you are sponsoring?

1 A. Yes. Mr. Lahtinen uses the 1996 price shape and the market price from the one-year forward
2 sale in Duquesne's RFP to calculate pro-forma generation audits and CTCs for 1999.
3 Prospectively, the use of the price shapes by Mr. Lahtinen to calculate CTCs each year will use
4 updated price shapes during the Transition Period.

5
6 Q. How do you use the price shape to convert the bid price into an hourly market price?

7 A. Mr. Schnitzer's testimony has described the process by which he has used the results of
8 Duquesne's forward sale of power to derive an all-hours spot price of electricity for each year of
9 the Transition Period. This all-hours price is simply the average market price at which a unit
10 could expect to sell power throughout the year. As I have described above, the price duration
11 curve is expressed as a percentage of the average yearly price. To calculate hourly prices, the
12 yearly all-hours price provided by Mr. Schnitzer is simply multiplied by the price duration curve
13 percentage for each hour of the year to yield hourly prices. This process is repeated for each year
14 of the transition, multiplying the yearly all-hours price by the price duration curve. The results of
15 that analysis are a set of hourly market price estimates for each hour of the Transition Period.

16
17 Q. Now that you have calculated an hourly market price for each year of the transition, how do you
18 calculate unit generation and operating cost?

19 A. The hourly market prices for the seven year Transition Period are entered into the PROMOD
20 production cost program as both a buying and a selling opportunity. As previously described in
21 Section III of my testimony, for each hour of the analysis, PROMOD dispatches generating units
22 on a lowest cost basis until either Duquesne's native load is served or marginal generating cost
23 equals the market price. If the marginal cost of Duquesne's generation reaches the hourly market
24 price before native load is served, the remaining load is served through a purchase from the
25 market. On the other hand, if Duquesne's load is met before the marginal cost of generation
26 reaches the market price, PROMOD will continue to dispatch generation until either marginal
27 cost equals marginal revenue or Duquesne's available generation is fully loaded. This process
28 continues through each hour of the study, and PROMOD accumulates the hourly operating cost

1 and output for each generating unit, which are standard outputs from PROMOD. This data is set
2 forth in Exhibits MGK-7A and MGK-7B.

3
4 Q. Does this analysis consider the costs associated with repeatedly starting and stopping generation
5 units in response to market prices?

6 A. The reason PROMOD was used for this analysis is that the actual operation of Duquesne's
7 system is more complicated than the simple economic dispatch described above. Large
8 generating units can not instantly start and stop in response to market economics, and the process
9 of starting a unit consumes considerable fuel and other resources. Generating units are incapable
10 of operating below minimum load levels. Likewise, the marginal generating cost is not linear
11 over unit output, and in fact, output itself is not increased linearly, but rather in a discrete series
12 of levels of output. All of these limitations and constraints are captured and considered in the
13 PROMOD analysis.

14
15 Q. If units are constrained from repeatedly starting and stopping in response to market prices does
16 this analysis assume Duquesne's generating system will operate in an uneconomic manner?

17 A. No it does not. The goal of the PROMOD dispatch logic, like the goal of a human system
18 operator, is to operate the generation system in the most economic manner possible. A human
19 operator, when considering the choice whether to start a shutdown unit or to increase output at an
20 operating facility, considers more than just the incremental operating cost of each choice. Before
21 incurring the cost of starting a unit, the human operator will make a judgment as to how long the
22 additional generation will be needed. If for example, this decision is being made late in the
23 afternoon, and the operator knows that load will decline quickly after the work day is over, the
24 operator may choose to increase output at an operating unit with a higher marginal cost than the
25 shutdown unit. This is the economic choice to make in this situation, and this is the way the
26 system is operated both in the real world and in the PROMOD analysis. A unit which could
27 somehow instantly start, stop, and change load levels all while operating at a baseload price

1 would be in a position to extract maximum revenue from the market. However, no such unit
2 actually exists.

3
4 Q. How are the unit output and operating costs used in Duquesne's restructuring plan?

5 A. The analysis described in this section of my testimony yields hourly unit output and operating
6 cost for each year of the Transition Period. As described in the testimony of Mr. Clayton, these
7 outputs are used to calculate the cost of generation service throughout the Transition Period.
8 This cost of service is used in Mr. Clayton's determination of Duquesne's remaining generation
9 book value in 2005 assuming maximum acceleration of depreciation and amortization consistent
10 with earning a fair rate of return.

11
12 **VI. Calculation of Cost and Market Revenue After the Transition Period**

13 Q. How has the analysis been simplified post-2005?

14 A. As described earlier in my testimony, the analysis uses an annual market price with generation
15 output based on unit availability. As described in Mr. Schnitzer's testimony, the purpose of
16 calculating the post-2005 market value of Duquesne's generation assets is to show that Duquesne
17 is entitled to a rate cap under Section 2804(4)(v). For purposes of this analysis, Mr. Schnitzer
18 has assumed that the cost of new entry in 2006 will set a ceiling on the market price. These price
19 ceiling estimates are used to estimate a range of market prices from which Mr. Clayton calculates
20 market value.

21
22 Q. What are the inputs used in this post-transition analysis?

23 A. The inputs for this analysis are the range of annual load-weighted market price ceilings described
24 by Mr. Schnitzer in his testimony, unit fuel price projections, unit availability data, and the
25 annual operating and maintenance costs provided in the testimony of Mr. Nelson and Mr.
26 Duckworth.

- 1 Q. Is PROMOD used to calculate unit operating costs in this analysis?
- 2 A. Yes. As I indicated previously, the hourly market price target is set to an artificially high value
3 to ensure that the unit will operate whenever it is available.
4
- 5 Q. How is generating unit revenue calculated in this analysis?
- 6 A. Generating unit revenue for the period from 2006 until the end of unit life is calculated by Mr.
7 Clayton on an annual basis. Annual unit capacity factor is assumed to equal that units'
8 equivalent availability. Annual generation is first calculated using PROMOD and provided as
9 an input to Mr. Clayton's analysis. This data is set forth in Exhibit MGK-8A.
10
- 11 Q. How do you calculate future generating unit operating costs for this analysis?
- 12 A. As with the analysis for the period through 2005, unit operating costs are calculated by
13 PROMOD. The model uses the fuel costs, operating and maintenance costs, and unit
14 performance and availability data previously described, to calculate annual unit operating cost
15 with the unit operating at its equivalent availability. These costs are set forth in Exhibit MGK-
16 7B.
17
- 18 Q. How are the results of this post-transition analysis used in Duquesne's restructuring plan?
- 19 A. This analysis accumulates unit generation and operating cost on an hourly basis from 2006
20 through end of unit life. These hourly results are accumulated into annual values, and are
21 included in Exhibits 8A and 8B, which are inputs to Mr. Clayton's analysis. Mr. Clayton
22 estimates the market value of Duquesne's generation assets as of December 31, 2005. Those
23 calculations are described in Mr. Clayton's testimony.
24
- 25 Q. Does this conclude your testimony?
- 26 A. Yes it does.

1. INTRODUCTION

L1 Overview

The PROMOD III® system is a computer software package that simulates the operation of an electric utility power system. It is first and foremost a comprehensive production costing model for projecting future operating costs. It can also be used to evaluate system reliability.

PROMOD III differs from less sophisticated production costing programs in its treatment of generating unit forced outages. It is these forced outages that comprise the major factor in the disruption of fuel budget forecasts, operating cost estimates, and projected utilization of high-cost peaking and mid-range units. Since these outages are random and unpredictable, PROMOD III employs a special mathematical technique to properly consider their resultant impact on fuel requirements and operating costs.

Forced outages are treated within the program by a complete probabilistic model. Generating units can be represented by a seven-state failure model to give explicit consideration to partial loss of unit capability and forced outages of varying severity. All possible failure states of each unit are considered, in combination with all possible failure states of all other units, in order to obtain the best possible forecast of expected fuel consumption, operating costs, and plant capacity factors.

For fuel budget applications and system planning studies, PROMOD III will produce better results than less sophisticated programs because of the comprehensive representation provided for simulating detailed electric utility operations on an hourly basis while recognizing the importance of generating unit full and partial forced outages. Without explicit recognition of these forced outages, accurate recognition of fuel consumption is not possible. PROMOD III also serves as a generation reliability program, since loss-of-load hours and emergency energy requirements are standard outputs. Both measures are needed to determine appropriate reserve levels.

PROMOD III has developed into the most effective tool for studying a host of problems confronting utilities today:

- Making Fuel Budget Forecasts
- Examining New Plant Capacity Additions
- Planning Nuclear Refueling Outages
- Projecting Utility Operating Costs
- Pricing Firm Power and Energy
- Analyzing Fuel Conversion and Restricted Fuel Supplies
- Investigating Demand-Side Management Programs
- Projecting Hourly Marginal Energy Costs
- Calculating Avoided Energy Costs and Cogeneration Rates

- Evaluating New Power Supply Technologies

In power system operations, the relative efficiencies (operating costs) of the generating units are used to match generator output with electric demand in the most economical manner. Numerous operating restrictions must be observed: spinning and quick-start reserve requirements, minimum shutdown restrictions, limitations of the transmission network, and deliverability restrictions of fuel suppliers, to mention only a few. These and other operational considerations are explicitly modeled in the PROMOD III program. Its strength lies in the combination of probabilistic production costing techniques with detailed modeling of operating considerations to produce realistic estimates of fuel consumption and operating costs.

Critical user features include:

- *Flexibility* - PROMOD III can simulate more generating unit types, utility system characteristics, and operating modes than any other probabilistic production costing program. The user can model various situations with as little or as much detail as required. Computer run time can be controlled by selectively activating only those modeling capabilities that are required for the study.
- *Ease of Use* - PROMOD III has a simple user interface that allows data to be entered in any order. Input override capability facilitates quick setup of change case runs by selective replacement of base case data with changed values.
- *Convenient Reporting* - PROMOD III produces a generalized data base from which the user can obtain a wide variety of standard printed reports. The PROMOD III system includes post-processors that can transfer model results to corporate and financial models, and help the user build customized reports.

1.2 Basic System Description

Figure 1-1 is a simplified block diagram of the PROMOD III system. Basic inputs, shown on the left side of the diagram, are generally described in Chapter 2, "Utility System Representation", and are described in detail in Chapter I, "Input Data". Briefly, these inputs fall into five categories:

- *Generating Unit Data* - unit types, heat rates, fuel types, capacity states, forced outage rates, seasonal derations, maintenance requirements, minimum downtimes, and penalty factors. Specialized data is required for nuclear, pumped hydro, conventional hydro and combined cycle units.
- *Fuel Data* - cost, availability, and inventory information for various fuels used by the generating units.
- *Load Data* - demand and energy forecasts, chronological load shapes, and levels of interruptible load. Historical load data in EEI load data format can be directly input to define chronological load shapes.
- *Transaction Data* - type, capacity, energy, availability, timing, and costs.

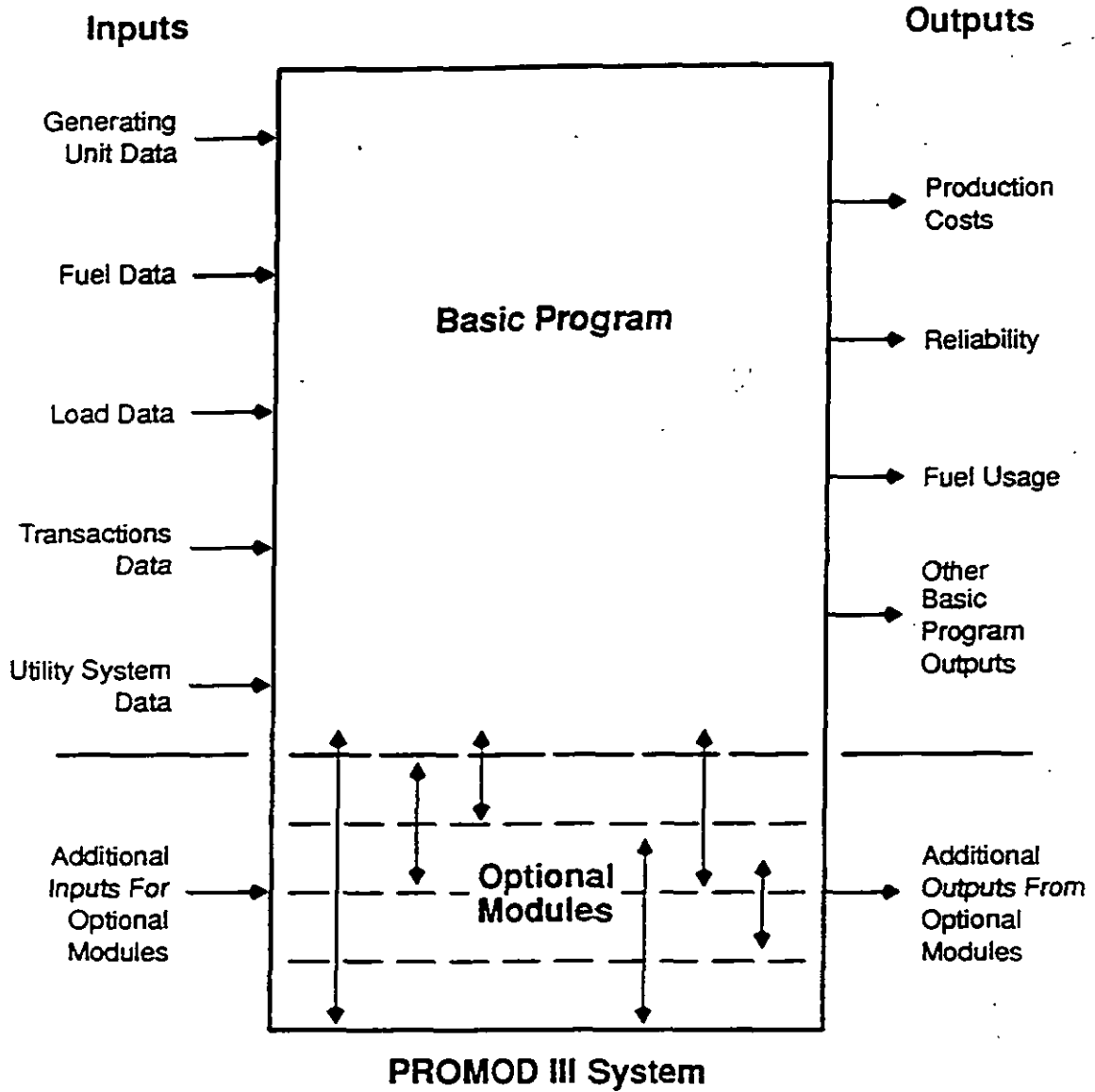


Figure 1-1. PROMOD III Block Diagram

- *Utility System Operating Data* - Operating reserve requirements, target reliability levels, emergency power purchase costs, available tie support, forbidden maintenance periods, and system-wide escalation rates.

Major outputs of the program, shown on the right side of Figure 1-1, are described and illustrated in Chapter O, "Output Reports".

Figure 1-1 shows how the optional modules interface with the basic program and with each other. These modules have been developed to:

- Model the behavior of unconventional generation resources, such as combined cycle units or pumped storage plants.
- Model utility system behavior under different operating modes, such as pooling (multi-area dispatch), emission restricted dispatch, and fuel supplies with limitations.
- Support studies by the rates (Hourly Marginal and Average Energy costs) and marketing (Controllable and End Use Load Management modules) departments.
- Develop customized reports and pass PROMOD III results to other models and databases (EXTRAC and Report Writer).

As shown in Figure 1-1, these optional modules usually require additional input data and provide additional output reports. Optional modules can be installed with the initial delivery of PROMOD III, or they may be added at any later time. The full set of optional modules offered is given below. Modules denoted by an asterisk (*) are described in this manual. Other modules have separate user's manuals.

- Hourly Marginal Energy Costing Module
- Hourly Average Energy Costing Module
- Combined-Cycle Unit Module
- Economy Energy Interchange Module
- Limited Fuel Module
- Nuclear Energy Allocation Module
- Energy Storage Module (pumped storage)
- Hourly Multi-Area Dispatch and Transmission Module (hourly interchange accounting)
- Multi-Company Reporting Module
- Environmental Dispatch & Reporting Module
- End-Use Load Management Module
- Controllable Load Management Module
- Multi-Area Reliability Module
- General Output Interface Module

With these capabilities, PROMOD III can be used to address a broad range of applications within the electric utility industry:

- *Production Costing* - This is the principal application of the program.
- *Fuel Budgeting* - Analyses can be performed on the basis of fuel costs, fuel requirements, fuel burns, inventory requirements or inventory values.

- *Reliability Analysis* - The program computes the amount of unsatisfied customer load (unserved energy) and the number of hours during which customer curtailments occur. PROMOD III automatically determines the amount of additional generating capacity needed to achieve a user-specified loss-of-load hours target. If capacity reserve levels exceed this acceptable service standard, then PROMOD III will determine the amount of surplus capacity which could be sold to neighboring systems on a firm basis.
- *Maintenance Evaluation* - Alternate maintenance schedules can be analyzed for their impact on production cost or system reliability.
- *Generation Planning* - Future capacity additions can be evaluated for production cost savings and improved system reliability. All types of generating unit alternatives can be studied, including coal, oil, nuclear, combined cycle, combustion turbines, hydro, and energy storage.
- *Marginal Energy Cost Analysis* - The program can report expected hour-by-hour marginal energy costs and hourly loss-of-load probability, key inputs to rate design studies. Interactive post-processing programs can be used in conjunction with these outputs to drive time-of-day and seasonal rates. This application requires the optional Hourly Marginal Energy Costing Module.
- *Energy Storage Evaluation* - The benefits of production cost savings and improved system reliability from pumped-hydro, compressed air energy storage projects, and battery storage can be determined. Selection of optimum capacity and storage reservoir size, and utilization of multiple projects can be studied. These evaluations require the optional Energy Storage Module.
- *Evaluation of Contract Transactions* - PROMOD III offers a number of modeling options for purchase and sale contracts.
- *Economy Energy Interchange Evaluation* - PROMOD III can be used to evaluate the effects of economy energy interchange, or changes in the opportunities for such interchange, on system operation, production costs and fuel consumption. The optional Economy Energy Interchange Module is required. In this case, an hourly price profile characterizes the neighboring systems' incremental operating costs for each month.
- *Hourly Multi-Area Dispatch* - When a number of utilities are operated as a pool, integrated operations can be analyzed with the PROMOD III Hourly Multiple Area Dispatch and Transmission Module. Centralized pool dispatch and the exchanges of economy energy between areas are modeled recognizing the bulk transmission network limitations. A flexible billing algorithm allows the user to test proposals for allocating the benefits of centralized dispatch simply by changing a few inputs. Using the Hourly Multiple Area Dispatch & Transmission Module, studies can be performed for a utility member company within a pool as well as for the entire pool. In these instances, fuel budgeting, generation planning, marginal energy cost analyses, energy storage economics and outside-system transaction evaluations can all reflect the benefits of pooled operation. Most importantly, the effects of adding transmission capabilities between areas can be studied.

- *Load Management* - PROMOD III can be used to analyze load management proposals at varying levels of detail. Overall daily, weekly, and seasonal load management strategies of various types can be modeled with the basic program. More precise study of modifications to user patterns (such as with hot water heaters or air conditioners) can be performed using the optional End-Use Load Management and Controllable Load Management modules.
- *Fuel Limitations* - The effects of fuel supply limitations and contractual restrictions on system operations and production costs can be analyzed with PROMOD III using the optional Limited Fuel Module. Minimum burn requirements, maximum available supply limits, take-or-pay contract provisions, maximum hourly consumption rates (e.g., gas flow rates), and suspension of coal deliveries can be modeled.
- *Environmental Constraints* - PROMOD III's optional Environmental Dispatch and Reporting Module calculates the release of atmospheric pollutants from fuel burned at utility plants. Restrictions can be imposed on the dispatch under varying environmental constraints allowing the user to analyze the system effects and direct costs which such conditions impose.

1.3 Illustration Of Probabilistic Modeling

At the heart of PROMOD III is a modeling technique which allows the explicit consideration of randomly occurring forced outages, forced derations and postponable maintenance outages of every generating unit and generation resource alternative. The probabilistic modeling technique accounts not only for the effects of a unit's outages and derations on its own operation, but also for the effects of a unit's outage on the operation of all other units in the utility system.

Probabilistic modeling is necessary from several standpoints:

1. Accurate prediction of peaking and mid-range capacity factors requires probabilistic treatment.
2. Monte Carlo techniques require prohibitive computer run-times to obtain statistically meaningful results.
3. PROMOD III's probabilistic technique, in effect, dispatches every possible configuration of the generation system, from one unit on outage at a time, two units on outage another time, and so on to the very unlikely but disastrous situation of all units on simultaneous outage. The properly weighted average of all such occurrences represents the best estimate of future operating costs.
4. Results must be repeatable from run to run. The probabilistic technique produces the best projection of the future; accurate forecasts are now possible in reasonable computer run times.

A simple example has been constructed below to provide an introduction to this technique. In this example, there is a single hour's load to be satisfied by two generating units. The value of the load is 150 MW. The generating unit to be considered first on the basis of cost, has a

capacity of 80 MW and an 80% probability of being available, while the second unit has a capacity of 100 MW and an availability of 90%.

In Figure 1-2, the loading of the first unit is depicted. The unit may be either available for service (probability 0.8) or unavailable (probability 0.2). In the event the unit is available, it will satisfy 80 MWH of load and leave 70 MWH remaining. In the event the unit is unavailable, it will supply nothing and 150 MWH will remain. The expected generation of unit 1 is therefore 64 MWH, and the expected remaining load is 86 MWH.

In Figure 1-3, the loading of the second generating unit is illustrated. Because of the two possible outcomes from the loading of the first unit, there are now four possibilities for the loading of the second unit. The calculations show that the expected generation of unit 2 is 68.4 MWH and the expected remaining load is 17.6 MWH.

If more units existed, the number of outcomes would continue to expand exponentially. For example, a relatively small system with 32 generating units would have more than 4.2 billion outcomes.

PROMOD III employs a computationally efficient algorithm that produces results identical to those obtained with direct enumeration of all availability states.

The PROMOD III algorithms include much more than a multi-state version of the probabilistic calculation illustrated above. The basic program contains dispatch logic capable of simulating the effect of unit commitment and economic dispatch carried out under detailed utility operating procedures as well as special computations for limited-energy resources including fixed-energy transactions, hydraulic resources and fixed-energy thermal units. The economic dispatch details have been deliberately omitted from the simplified discussion above. Still further complexities in the calculations arise in the extended modeling capabilities of the optional modules.

PROMOD III combines probabilistic modeling with (1) the flexibility to analyze diverse types of generating units and complex purchase and sale arrangements and, (2) the capability to reflect real world utility operating procedures. PROMOD III can quickly supply management with accurate production cost estimates for a wide variety of generation expansion scenarios or operational strategies and soon becomes an indispensable tool for the utility system planner and operational planner. The probabilistic structure, detail and accuracy also make PROMOD III the perfect tool for related applications ranging from supplying cost information for use in rate proceedings to analyzing the benefits of load management programs. PROMOD III enables utility system planners and operators to develop efficiently and accurately the ever-increasing amount of information that is being demanded by management and by regulatory agencies.

Most importantly, the information is developed consistently from analysis to analysis. Users derive additional benefit from the combined experience of the planning staffs of PROMOD III's growing utility base. PROMOD III is continually maintained and enhanced by EMA, making it responsive to new production costing applications and modeling requirements. The continuing evolution of the program and EMA's commitment to keep PROMOD III as the industry standard will extend its useful life indefinitely.

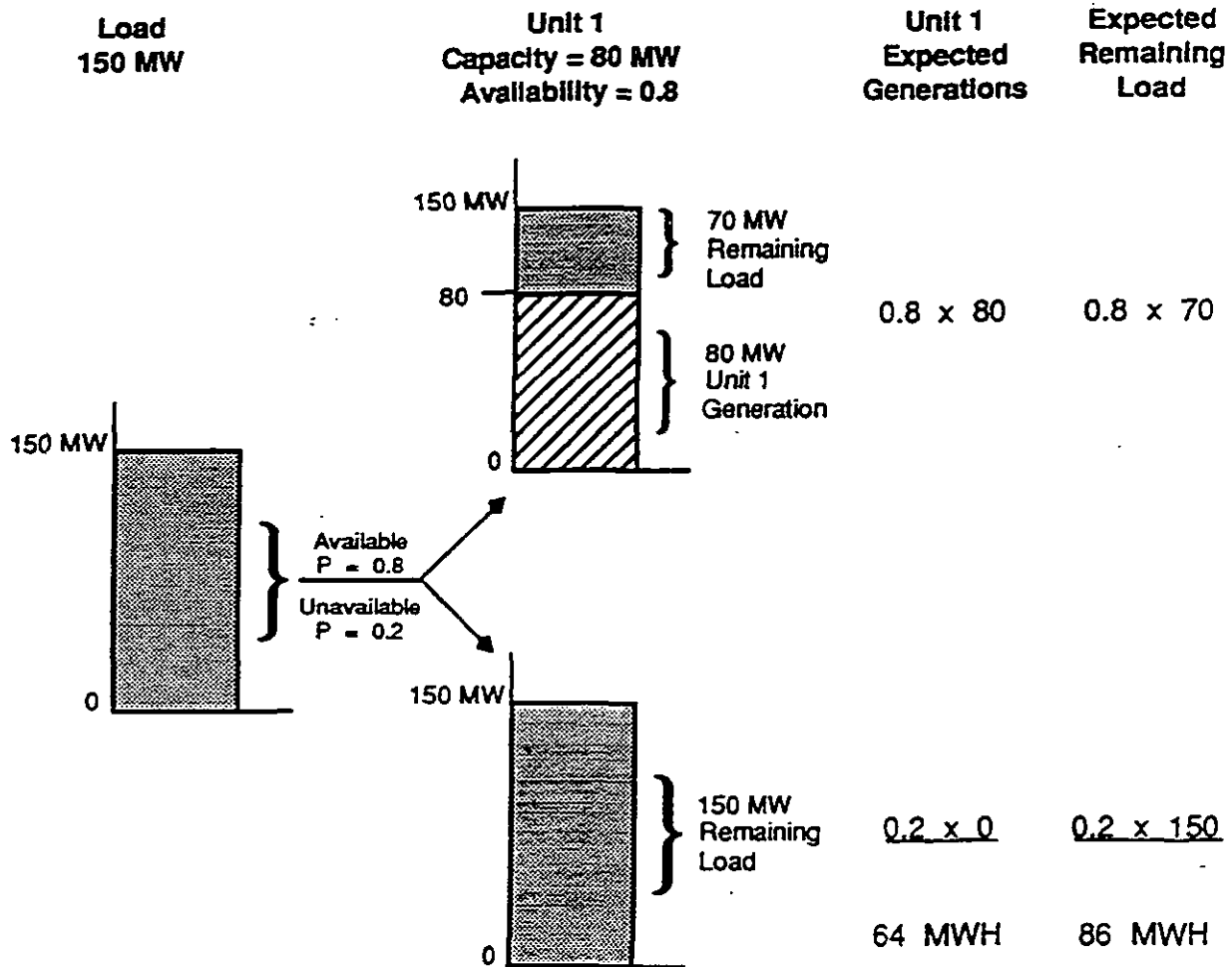


Figure 1-2. Probabilistic View of Loading One Unit

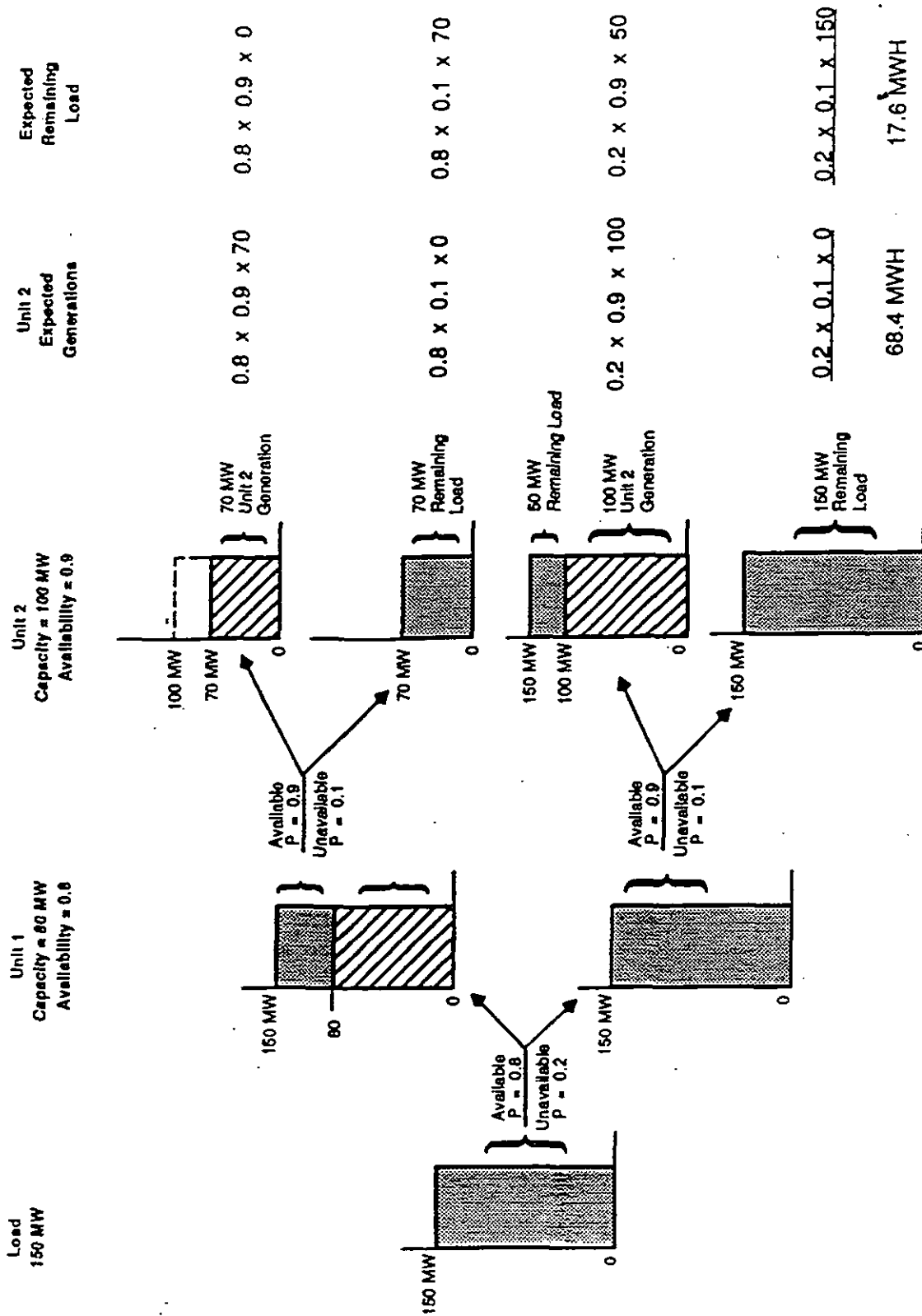
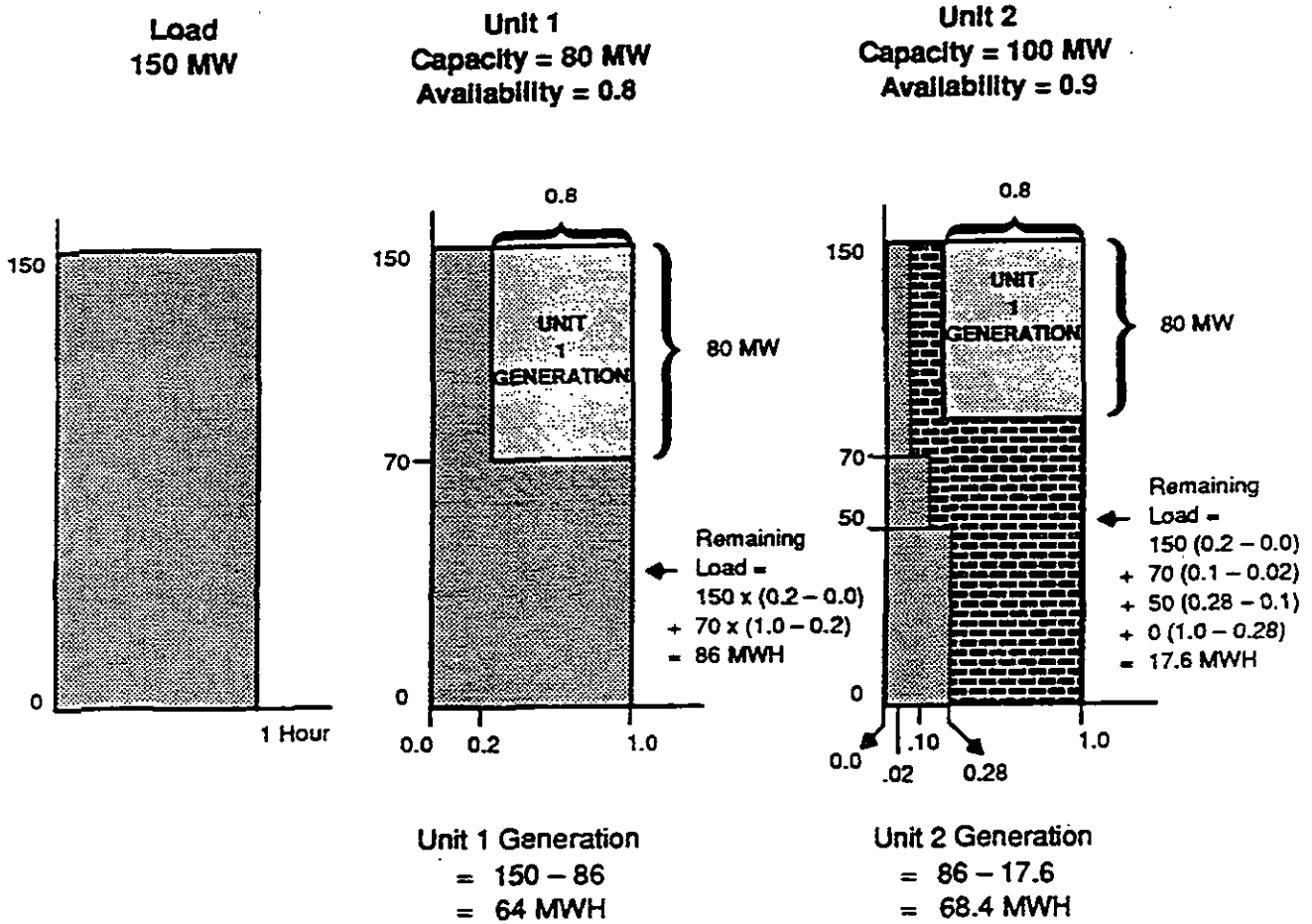


Figure 1-3. Probabilistic View of Loading Two Units



PROMOD III's Method Of Probabilistic Simulation

Duquesne Light Company
Fossil Plant Fuel Cost cents/ mmBtu

Year	Cheswick	Elrama	Sammis	Eastlake	Mansfield	SO2 Allow \$/ton
1997	115.7	105.6	128.5	133.9	159.4	100
1998	118.1	106.0	132.7	119.8	164.0	108
1999	121.4	108.4	136.3	121.5	161.0	115
2000	125.1	107.6	145.1	125.1	108.8	133
2001	129.0	108.2	152.0	128.7	107.5	143
2002	131.5	111.1	155.0	132.6	110.1	153
2003	134.9	114.2	161.0	136.7	113.3	164
2004	138.9	117.5	163.5	140.6	116.5	177
2005	143.4	120.8	169.3	144.8	119.9	190
2006	148.5	124.2	165.7	149.4	123.3	204
2007	152.5	127.7	171.2	153.7	126.9	219
2008	157.6	131.4	178.3	158.3	130.5	234
2009	170.3	135.0	185.4	163.2	134.3	252
2010	177.2	138.9	193.1	167.9	138.1	271
2011	183.6	142.9	200.9	172.9	142.1	290
2012	190.0	146.9	209.1	178.4	146.1	311
2013	196.7	151.1	217.4	183.5	150.5	334
2014	203.7	155.4	226.7	189.1	154.7	358
2015	211.1	159.7	235.7	194.8	159.3	384
2016	218.5	164.4	245.8	200.6	163.8	412

Duquesne Light Company
Nuclear Plant Fuel Cost cents/ mmBtu

Year	Beaver Valley 1	Beaver Valley 2	Perry	Spent Fuel \$/ MWhr
1997	47.24	40.00	57.28	1.00
1998	45.11	41.60	53.83	1.00
1999	45.39	42.07	60.15	1.00
2000	44.00	43.39	56.22	1.00
2001	43.72	44.71	62.63	1.00
2002	45.85	44.24	59.28	1.00
2003	45.48	45.46	63.68	1.00
2004	46.22	47.06	60.72	1.00
2005	49.82	46.88	64.35	1.00
2006	49.92	48.57	61.48	1.00
2007	51.86	50.73	65.31	1.00
2008	53.98	52.90	67.60	1.00
2009	56.11	55.06	70.09	1.00
2010	58.42	57.32	72.48	1.00
2011	60.92	59.58	75.16	1.00
2012	63.32	62.03	77.74	1.00
2013	65.82	64.57	80.51	1.00
2014	68.40	67.11	83.48	1.00
2015	71.09	69.84	86.35	1.00
2016		72.63	89.41	1.00
2017		75.53	92.47	1.00
2018		78.56	94.96	1.00
2019		81.70	97.53	1.00
2020		84.97	100.16	1.00
2021		88.37	102.86	1.00
2022		91.90	105.64	1.00
2023		95.58	108.49	1.00
2024		99.40	111.42	1.00
2025		103.38	114.43	1.00
2026		107.52	117.52	1.00

Duquesne Light Company
Projected General Escalation Rate (GNP Deflator)

Year	Yearly Price Increase (%)
1997	2.4
1998	2.5
1999	2.5
2000	2.5
2001	2.6
2002	2.6
2003	2.7
2004	2.7
2005	2.7
2006	2.7
2007	2.6
2008	2.6
2009	2.7
2010	2.7
2011	2.7
2012	2.7
2013	2.7
2014	2.7
2015	2.7
2016	2.7
2017	2.7
2018	2.7
2019	2.7
2020	2.7
2021	2.7
2022	2.7
2023	2.7
2024	2.7
2025	2.7
2026	2.7

Duquesne Light Company
Projected Unit Equivalent Availability (Annual %)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Cheswick	67.6	80.4	80.8	77.4	84.1	80.8	70.8	77.4	84.1	80.8	77.5	84.1	70.7	77.4
Elrama 1	65.5	58.5	65.5	69.6	68.2	65.4	69.6							
Elrama 2	56.4	58.7	48.0	59.9	58.7	56.3	59.9							
Elrama 3	55.7	52.5	62.5	58.8	61.3	62.5	58.8							
Elrama 4	65.7	77.9	70.4	70.4	77.9	60.0	70.4							
Sammis	91.2	82.5	91.2	82.2	84.5	84.2	91.2	84.2	91.2	75.5	91.2	84.2	91.2	
Eastlake	73.8	55.9	79.5	70.8	70.8	79.3	71.5	66.4	69.0	70.8	71.7	79.1	70.8	72.5
Mansfield 1	82.7	89.6	72.4	89.6	82.7	89.6	82.7	89.6	69.0	89.6	82.7	89.6	82.7	89.6
Mansfield 2	85.0	92.0	77.9	88.5	85.0	92.0	85.0	92.0	74.4	88.5	85.0	92.0	85.0	92.0
Mansfield 3	90.8	85.6	90.8	81.8	78.8	83.8	90.8	83.8	90.8	87.0	73.7	83.8	90.8	83.8
Perry	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2
Beaver 1	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5
Beaver 2	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cheswick	84.1	80.8	77.4											
Elrama 1														
Elrama 2														
Elrama 3														
Elrama 4														
Sammis														
Eastlake														
Mansfield 1	69.0	89.6	82.7	89.6										
Mansfield 2	74.2	88.7	85.0	92.0	85.0									
Mansfield 3	90.8	74.6	86.1	83.8	90.8	83.8	90.8	90.8						
Perry	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2	93.5	83.2	93.5	93.5
Beaver 1	82.5	94.1	82.5	82.5										
Beaver 2	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5	94.1	82.5	82.5	94.1	94.1

Duquesne Light Company
Book Life Retirement Dates - Nuclear Plants

Beaver Valley 1	January	2016
Beaver Valley 2	January	2026
Perry	March	2026

Book Life Retirement Dates - Fossil Plants

Cheswick	January	2015
Sammis	January	2011
Eastlake	January	2012
Elrama	January	2005
Mansfield 1	January	2016
Mansfield 2	January	2017
Mansfield 3	January	2020
Brunot Island 1A, 1B, 1C	January	2012
Brunot Island 2A, 2B	January	2013

Duquesne Light Company
Projected Annual Unit Output (GWhr)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Cheswick	3272	3599	3647	3528	3830	3723	3296	3652	4197	4032	3876	4195	3528	3865
Elrama 1	541	459	517	544	537	514	551							
Elrama 2	456	458	373	466	462	440	467							
Elrama 3	533	473	572	531	558	571	533							
Elrama 4	990	1131	1028	1017	1133	862	1011							
Sammis	1370	1215	1326	1212	1232	1251	1366	1271	1493	1236	1498	1378	1474	
Eastlake	1110	827	1165	1040	1052	1172	1057	1000	1120	1149	1166	1286	1149	1178
Mansfield 1	1580	1642	1344	1698	1567	1712	1594	1738	1376	1789	1657	1787	1652	1789
Mansfield 2	449	465	395	454	436	477	448	490	404	481	463	499	461	500
Mansfield 3	869	791	845	759	730	781	853	787	874	839	712	807	875	808
Perry	1343	1191	1347	1195	1343	1195	1346	1195	1343	1195	1346	1195	1343	1195
Beaver 1	3172	2781	2790	3172	2781	2781	3181	2781	2781	3172	2790	2781	3172	2781
Beaver 2	816	816	934	816	816	931	819	816	931	816	819	931	816	816
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cheswick	4211	4032	3828											
Elrama 1														
Elrama 2														
Elrama 3														
Elrama 4														
Sammis														
Eastlake														
Mansfield 1	1382	1789	1652	1769										
Mansfield 2	404	482	461	500	455									
Mansfield 3	877	719	829	808	877	808	875	869						
Perry	1346	1195	1343	1195	1346	1195	1343	1195	1347	1196	1343	1195	1347	1343
Beaver 1	2790	3172	2781	3137										
Beaver 2	934	816	816	931	819	816	931	816	819	931	816	816	934	816

Duquesne Light Company
Projected Annual Unit Production Cost (\$millions)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Cheswick	68.0	66.1	69.1	70.9	77.2	75.4	84.5	81.9	93.5	94.7	95.6	106.6	110.0	110.1
Elrama 1	11.6	13.2	12.4	13.5	13.5	13.6	14.6							
Elrama 2	10.2	11.2	11.6	11.8	11.9	11.9	12.7							
Elrama 3	11.6	13.7	13.2	13.3	13.9	14.5	14.1							
Elrama 4	20.2	23.8	21.9	22.9	25.1	24.8	24.7							
Sammis	22.9	22.8	24.2	24.9	25.3	27.8	28.2	29.6	31.1	30.1	33.6	35.0	35.8	
Eastlake	21.6	19.0	23.9	23.1	24.2	26.8	26.2	26.5	29.7	31.1	32.6	36.2	34.9	36.9
Mansfield 1	37.7	40.2	29.5	31.0	30.7	32.5	33.2	35.7	34.6	38.5	38.2	41.0	40.7	43.6
Mansfield 2	10.5	11.1	8.3	8.5	8.4	8.9	9.1	9.9	9.7	10.5	10.4	11.3	11.2	12.0
Mansfield 3	19.3	18.7	14.9	14.9	15.4	15.0	17.1	16.2	17.8	18.4	18.3	18.8	20.8	19.8
Perry	25.3	27.5	25.1	28.9	30.5	30.4	32.1	31.9	33.7	33.6	36.2	35.9	38.6	38.3
Beaver 1	52.9	63.0	56.9	48.4	60.3	61.7	52.7	66.2	67.9	58.1	72.9	75.3	64.4	80.7
Beaver 2	17.8	17.0	13.7	16.6	16.9	14.8	18.1	18.5	16.1	19.8	20.5	17.9	22.0	22.7
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cheswick	120.2	122.2	122.3											
Elrama 1														
Elrama 2														
Elrama 3														
Elrama 4														
Sammis														
Eastlake														
Mansfield 1	41.6	46.0	45.6	49.7										
Mansfield 2	11.6	12.5	12.4	13.8	13.3									
Mansfield 3	21.4	21.0	22.9	23.1	25.3	22.2	24.3	24.8						
Perry	41.3	40.8	44.0	43.6	47.1	52.9	50.1	56.4	53.5	58.2	53.3	58.2	53.5	61.2
Beaver 1	83.6	71.4	89.4	75.6										
Beaver 2	19.9	24.3	25.2	21.8	26.5	27.2	23.5	28.7	29.4	25.4	31.0	31.8	27.5	26.9

VOLUME IV

Duquesne Statement No. 10

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

**Direct Testimony
of
Ralph L. Nelson**

Contents:

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

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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

1 range), cost reduction strategies, Clean Air Act Amendment (CAAA) Compliance
2 Strategies, and the performance of benchmarking analyses.

3 Q. Please describe your current responsibilities at Duquesne.

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

12 Q. Have you previously testified before this Commission?

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

15 **II. Purpose of Testimony**

16 Q. Please state the purpose of your testimony.

17 A. The purpose of my testimony is to explain the basis for Duquesne's projections of the
18 operating and maintenance costs for the fossil generating stations including those which
19 are wholly owned and operated by Duquesne and those in which Duquesne has
20 ownership interest but are operated by other electric utility companies. I will also explain
21 the basis of Duquesne's projections of capital expenditures for the previously mentioned
22 fossil stations, including those capital expenditures related to environmental compliance

1 projects. Finally, I will discuss the basis for the availability factor projections for these
2 fossil generating stations. All of the above information has been provided to Mr. Mark
3 G. Karl to support the development of the generation cost of service for the years 1999 to
4 2005 and an estimate of generation revenue net of variable cost beyond 2005.

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

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

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

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

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

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

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

18 Exhibit RLN-3 is a bar graph which displays the historical O&M expenses from 1988
19 forward as well as the projected expenses for the years 1997 through 2016. As the result
20 of organizational changes and changes in cost allocations as well as some accounting
21 changes that took place prior to 1993, it was impossible to capture the historical costs
22 exactly as tabulated in Exhibits RLN-1 & RLN-2. Nevertheless, the graph represents

1 with reasonable accuracy, savings achieved by Duquesne's cost reduction efforts and the
2 trend of historical as well as projected O&M expenses. During the period 1988 to 1993,
3 expenses were reduced by approximately 15% and from 1993 through 1996, expenses
4 have increased at approximately the same rate as inflation. However, during this period
5 expenses have exceeded the 1988, 1989, 1990 average in only two years. In 1997,
6 expenses are projected to decrease sharply, primarily because of the sale of Duquesne's
7 interest in Ft. Martin No. 1 Unit and thereafter are trending upward at a rate slightly less
8 than inflation. After 1997, expenses will exceed the 88, 89, 90 average in only two years,
9 which are those years in which Cheswick is scheduled for major maintenance outages.

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

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

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

18 A. Duquesne has implemented a variety of strategies during the past five or six years
19 including staffing reductions, lengthening the interval between major overhaul outages
20 and the sale of generating assets, to name a few. Over the past five or six years, staffing
21 at Duquesne's wholly owned generating and generating support facilities has been
22 reduced by 106 people or approximately 22% of the work force at an annual savings of

1 approximately \$4 million per year. There have been similar staff reductions at those
2 fossil generating stations in which Duquesne is a joint owner. These reductions have
3 been achieved through the implementation of various strategies such as process re-
4 engineering, outsourcing certain functions that can be performed more efficiently by
5 outside contractors and by developing a multi-crafted more productive workforce.
6 Another example of a cost reduction strategy which has been implemented is the
7 lengthening of the interval between planned maintenance outages. This has been
8 accomplished by improving the maintenance work scheduling process and by
9 implementing various predictive maintenance techniques. More recently, Duquesne sold
10 its fifty percent interest in the Fort Martin No. 1 Unit which decreased our O&M
11 expenses by approximately five million dollars per year. As the result of these and other
12 cost reduction efforts, and as indicated in the bar graph in Exhibit RLN-3, during the
13 period 1988 through 1993 Duquesne has been able to reduce O&M expense by
14 approximately 15% and since then, we have limited cost increases to the rate of inflation.

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

17 A. In my opinion, there are no substantial opportunities for reductions in the non-fuel O&M
18 expenses at Duquesne's fossil generating stations. This applies to both the wholly owned
19 and jointly owned stations. Duquesne and the operating companies at the jointly owned
20 fossil stations have been very aggressive over the past five or six years in our efforts to
21 reduce costs in anticipation of pending competition. As stated earlier in my testimony,
22 Duquesne has significantly reduced staffing levels in order to reduce labor costs and

1 present plans call for continued staffing reductions through the year 2002. We will
2 continue our efforts to improve productivity through the implementation of new work
3 systems such as multi - crafting and self directed work teams and we will continue to
4 implement new technologies as they develop, but as the result of inflation, aging of the
5 fleet and boiler degradation due to the long term effects of mitigating nitrogen oxide
6 emissions, there will be continuous upward pressure on O&M costs. Therefore, in my
7 opinion we will not realize substantial O&M cost reductions until the year 2004, and this
8 is reflected in the total O&M cost projections shown in Exhibit RLN-2 in constant 1996
9 dollars.

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

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

20 **IV. Capital Expenditure Projections**

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

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

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

20 A. For each of Duquesne's wholly owned fossil stations the 1997 Capital budget was
21 developed internally under the general direction of the Vice President of the Power
22 Supply Group. This budget was prepared in detail on a station specific basis. For the

1 jointly owned fossil stations, the 1997 budget was based on information provided by the
2 operating companies on a station specific basis for Duquesne's share of the station (unit).

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

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

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

14 A. Yes, I believe the projected levels of expenditures are reasonable. As shown in Exhibit
15 RLN-6 (which tabulates the historical and the projected capital expenditures on a constant
16 1996 dollar basis), except for two years during the period 1997 through 2004, the
17 projected levels of expenditures are less than the average of the years 1994 to 1996.
18 Capital expenditures in 1998 and 2004 exceed the average by a significant amount
19 because Cheswick Power Station is scheduled for a major maintenance outage in each of
20 those years. After the year 2004, capital expenditures decline sharply as stations (units)
21 reach the end of book life and their capital expenditures are reduced to zero.

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

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

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

13 **V. Equivalent Availability Factors**

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

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

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

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

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

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

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

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

18 A. Generally, there is a link, in that in order to maintain station performance in terms of
19 availability (EAF) and reliability, capital spending must be maintained at some minimum
20 levels for routine replacement of worn out components. However, there is no rigorous
21 mathematical relationship linking EAF to capital spending and by implementing new
22 technologies and addressing the root cause of equipment or component failures that result

1 in the largest contribution to forced outages and forced derates, it is possible to improve
2 EAF while reducing capital expenditures.

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

5 A. Yes, it is.

6 Q. Does this conclude your direct testimony?

7 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)

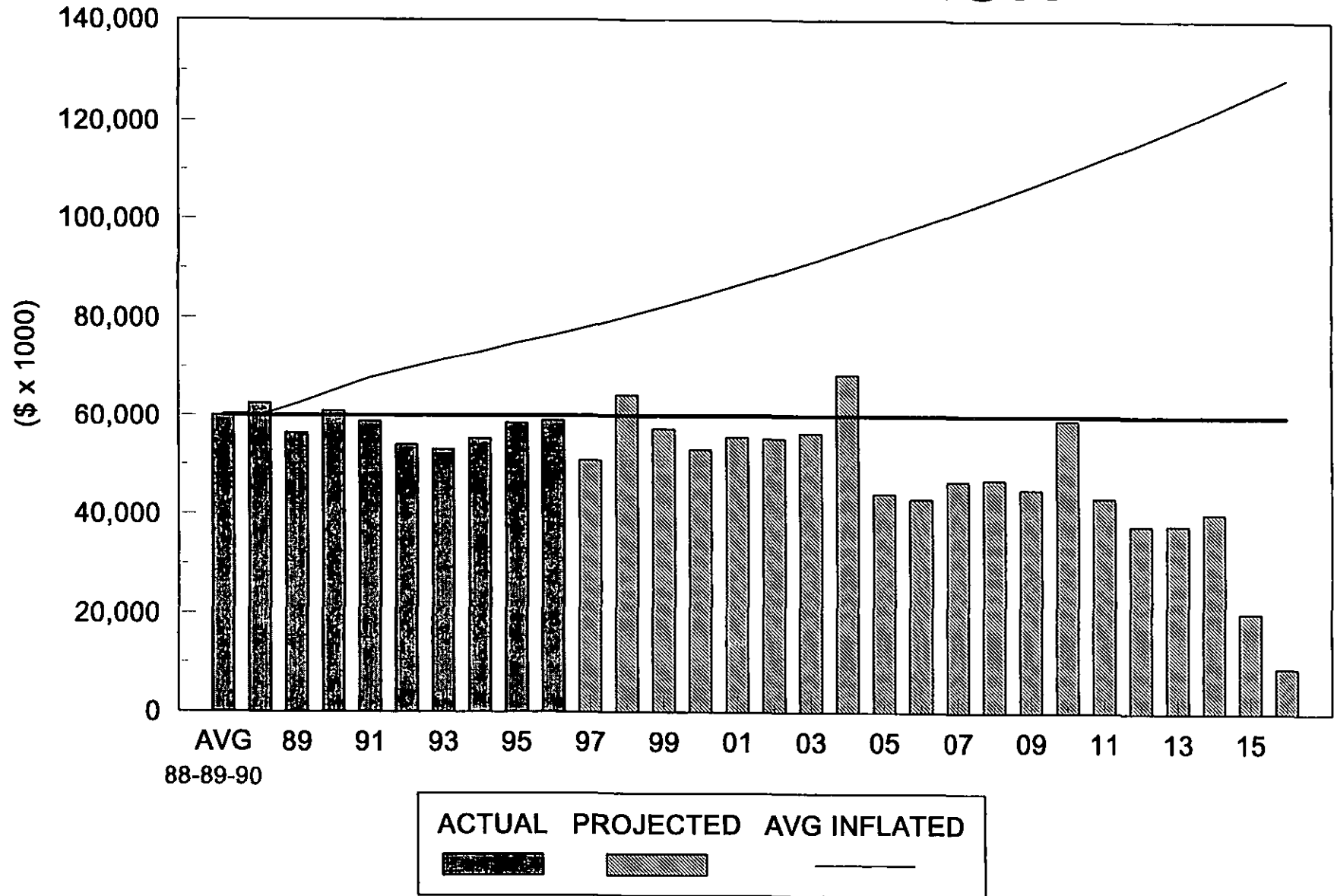
STATION		CHESWICK	ELRAMA	BRUNOT IS	PHILLIPS	EASTLAKE	SAMMIS	MANSFIELD	TOTAL
1993	(A)	19,475	17,936	277	125	5,688	4,816	9,541	57,858
1994	(A)	14,797	18,084	325	225	4,166	5,720	15,741	59,058
1995	(A)	16,765	19,044	334	165	5,319	6,391	12,261	60,280
1996	(A)	18,492	21,891	341	178	3,814	3,638	12,817	61,171
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



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.		Likely case - no impact.	In 2000, need 40,000 tons additional annual reduction to meet CAP, factor in at \$___/ton. Includes Eastlake 5 and Sammis 7 (2)
	55% reduction in 1999 (1)	65% in 2005(1)		EPA shifted away from PM-10 to PM-2.5 which is composed of secondary sulfate and nitrate compounds.			
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.	Both are addressed by Acid Rain Program SO ₂ and Title I NO _x controls	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	N/A	N/A	N/A		N/A		
Simple cycle with HRSGs	Water or steam injection w. or s.i.	w. or s.i.					
Simple cycle with HRSGs and suppl. firing		w. or s.i.					
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 SO₂ reduction applies on a system basis, including jointly owned plants.

EAU(3):421-97

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	0	0	
RSW	2,074	747	1,586	1,469	2,140	4,640	890	7,810	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	6,673	15,045	4,531	3,136	1,664	1,063			
ELRAMA																									
GEN. CAP	8,636	4,913	6,807	6,785	10,148	5,172	3,261	3,951	3,052	2,098	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	2,280	270	60	0													
TOTAL	15,341	9,104	9,091	11,178	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	0				
RSW	0	0	0	0	460	0	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	833	32	539	656	1,489	1,234	338	222	778	1,258	3,034	3,469	2,258	528	770	764	905	621						
CAAA	88	98	2	62	1,237	1,637	800	100	5,040	5,100	300	0	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	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	528	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	0						
RSW	0	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	7,718	3,545	3,927	1,734	3,869	2,902	7,312	3,073	3,703	829	1,063	
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	0	
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	6,140	5,430	7,718	0	1,673	2,041	3,278	2,041	4,956	0	2,317	0	460	
TOTAL																									
GEN. CAP	21,611	17,602	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	4,678	829	1,063	
CAAA	10,313	6,047	4,968	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	17,558	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	

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	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	16,649	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	3,578	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	0			
RSW	0	0	0	0	449	0	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	568	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	836	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	7,886	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

VOLUME IV

Duquesne Statement No. 11

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

**Direct Testimony
of
Ralph Duckworth, Jr.**

Contents:

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

DIRECT TESTIMONY OF RALPH E. DUCKWORTH, JR.

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

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

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

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

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

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

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

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

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

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

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

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

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

14 Q. What is the purpose of your testimony?

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

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

- 1 A. I projected non-fuel O&M expenses on a unit basis expressed in 1996 dollars. These
2 expenses were escalated for future years using a general inflation factor provided by
3 Mr. Karl. O&M projections for Beaver Valley Units 1 and 2 are based on our internal
4 nuclear group forecasts for 1997 and beyond, and have been normalized to levelize
5 the cost impact of refueling outages, which occur on an 18 month cycle. O&M
6 projections for the Perry Plant were provided by Centerior, the operator of the plant,
7 and reflect a similar normalization to levelize costs for refueling outages.
- 8 Q. Do your projections assume any productivity gains or other cost reductions?
- 9 A. Yes. The Beaver Valley projections for 1997 through 1999 reflect plans to further
10 reduce contractor support and some reduction in utility labor costs due to efficiencies
11 gained through reorganization and improvements in our processes. Significantly
12 higher reductions are expected in 2000 and 2001 as the result of implementing key
13 strategies to improve Beaver Valley's infrastructure and core processes through a plan
14 called "Excellence 2000". These projections also reflect reduced refueling outage
15 costs due to improved planning and scheduling of work during those outages.
- 16 Q. How will those reductions be achieved?
- 17 A. Beaver Valley is currently making a number of major changes to our work planning
18 and scheduling processes, our project management capability, and maintenance and
19 engineering data bases. These changes, when implemented, will allow us to perform
20 more tasks with less manual effort and intervention, and to perform those tasks more
21 efficiently. This, in turn, will allow us to reduce the number of contractors and utility
22 employees at the site.
- 23 Q. When will these changes take place?

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

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

6 A. Yes. Perry has made significant improvement in reducing its costs over the last two
7 years. As shown in Exhibit RED-1, Perry achieved a 21% reduction in its costs from
8 1994 to 1996. Further improvements are expected as a result of Perry's implementing
9 additional process improvements through a program called "Perry Plan For
10 Excellence".

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

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

16 Q. How do these projections compare to past experience?

17 A. Actual O&M expenses for all generating stations for the years 1992-1996 are shown
18 in Exhibit RED-1. With respect to most of the stations individually, and on an overall
19 basis, the 1997 projection is less than the average of the prior three years' experience.
20 Further, projections for 1998 through 2000 show additional reductions for the process
21 and structural improvements discussed above. Thereafter, costs are increased for the
22 effects of inflation. Additionally, data for years 1992-1996 are expressed in current
23 year dollars. If they are expressed on a constant dollar basis using the inflation

1 factors supplied by Mr. Karl, it shows a clearer picture as to how conservative our
2 forecasts are. Exhibit RED-2 provides the constant dollar comparison.

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

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

13 Q. Why do you believe these projections are aggressive?

14 A. As just discussed, these projections represent a significant reduction from past
15 experience. If achieved, O&M expenditures for the year 2001 will represent a 60%
16 reduction in constant dollars from the 1994-1996 three year average, as shown in
17 Exhibit RED-2. Further, projected expenditures for Beaver Valley Units 1 and 2 for
18 2001 are 36% less than the 1993-1995 three year average for Westinghouse two unit
19 sites on a constant dollar basis (see Exhibit RED-2).

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

22 A. I do not believe so. We have been successful in recent years in our efforts to control
23 O&M costs in the face of ongoing inflationary pressures. I believe that the

1 projections developed for 2000 and subsequent years represent aggressive targets
2 which are well below our actual experience in the last three years. As an example of
3 our ability to reduce costs, Beaver Valley Unit 1's 11th refueling outage in 1996 cost
4 \$29.7 million, almost \$20 million less than its 9th refueling outage in 1993 which
5 cost \$49.1 million. Further, refueling outage duration decreased from 83 days in
6 1993 to 49 days in 1996 and represented the shortest outage in the Unit's history.

7
8 Although Beaver Valley Unit 2's 6th refueling outage in 1996 was unusually long at
9 107 days and cost \$34.2 million, its 5th refueling outage in 1995 was only 45 days
10 long and cost \$26.3 million. This represents a significant improvement over the
11 Unit's 4th refueling outage in 1993 which was 81 days long and cost \$30.5 million.
12 Perry has also made significant improvements in its refueling outages. Its 5th
13 refueling outage in 1996 was 76 days long, down from 190 days during its 4th
14 refueling outage in 1994, and cost \$52.9 million, down from \$93.3 million.

15
16 Further reductions in outage cost and outage duration are planned for all three units.
17 Additionally, we have reduced staffing by 130 people at Beaver Valley at an annual
18 savings of approximately \$6.5 million in direct labor costs over the past several years.
19 Contractor levels at Beaver Valley have decreased by 45 over the last 2 years, at an
20 estimated savings of \$ 3 million per year. Staffing levels at Perry have decreased by
21 134 people over the last 3 years at an estimated annual savings of \$6.7 million. Perry
22 has completed a major improvement program entitled the "Perry Course of Action",
23 which has allowed Perry to reduce its O&M costs by 38% on a constant dollar basis

1 from 1993 to 1997 (budget). (See Exhibit RED-2.) Process improvements and
2 reorganization have enabled the nuclear plants to achieve these levels of
3 improvement. As we implement further structural and process improvements, we
4 expect further cost reductions through the year 2000. However, it would not be
5 reasonable to assume a continuation of this trend after that date.

6 Q. Why are further reductions not reasonable?

7 A. Our foremost concern with operating a nuclear plant is safety. It is of the utmost
8 importance to maintain a safe plant. It will be necessary to make further changes and
9 improvements to maintain a high level of safety at the nuclear plants and to comply
10 with Nuclear Regulatory Commission requirements. It is essential to maintain high
11 safety standards, and it will require a significant level of ongoing resources to
12 continue to operate safely. It would be imprudent to project a lower level of
13 expenditures, especially after achieving the reductions projected through the year
14 2000. Further, there is significant uncertainty regarding future government
15 regulation. For example, the United States Department of Energy ("DOE") is
16 obligated to take possession of spent nuclear fuel beginning in 1998. The DOE has
17 already stated that it will not be able to receive spent fuel until 2010 at the earliest.
18 Failure by the DOE to meet its obligations could force utilities, including DLC, to
19 spend millions of dollars in unforeseen costs to store spent nuclear fuel.

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

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

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

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

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

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

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

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

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

21 A. The term stranded investment is a financial term, not an operating term. Whether or
22 not a portion of the plant investment is stranded is irrelevant in determining the level
23 of expenditures necessary to operate the plant. The continued operation of a plant

1 requires a certain level of expenditures. Certain of these expenditures are capitalized
2 and others are expensed. It is accounting rules established by the Federal Energy
3 Regulatory Commission (FERC) that determine which of these expenditures are
4 operation and maintenance expense and which are capital expenditures. Capital
5 expenditures necessary for the routine operation of the plant are included in the base
6 level of capital expenditures.

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

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

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

13 A. Yes. The projected capital expenditures, exclusive of the incremental expenditures
14 for 1997, 1998 and 1999, are consistent with prior years and are among the lowest
15 levels in the industry. Beaver Valley's average capital expenditures for the period
16 1994 to 1996 are less than one-half of the average 1996 capital expenditures for two-
17 unit Westinghouse PWR sites. Exhibit RED-3 provides the data, in current dollars,
18 that establish this fact. As with operating and maintenance expense, if a constant
19 dollar comparison is made, there is actually a reduction in capital expenditures of
20 nearly 50% from 1992's levels. This comparison is provided in Exhibit RED-4. On a
21 constant dollar basis, projected capital expenditures for Beaver Valley Units 1 and 2
22 for the year 2001 are 41% lower than the average 1996 capital expenditures for
23 Westinghouse two-unit PWR sites (see Exhibit RED-4).

- 1 Q. Why are Perry's recent capital expenditures greater than the industry average?
- 2 A. As previously stated, Perry is completing the Perry Course of Action and the Perry
3 Plan for Excellence. These plans include significant plant improvements, including
4 repairs to the service water and circulating water piping systems. They also include
5 the Perry Activity & Resource Management System, which will design and install
6 hardware and software to streamline the work order system and the work management
7 process. As shown in Exhibit RED-3, once these improvements have been
8 completed, Perry's projected capital expenditures fall well below the 1996
9 comparative average. When stated in constant dollars in Exhibit RED-4, Perry's
10 average projected capital expenditures in years 2000 and beyond are less than 50% of
11 the 1996 comparative average.
- 12 Q. Do you believe that Mr. Karl's projection of future increases in capital investment
13 for these stations is reasonable?
- 14 A. Yes I do, for the same reasons I expressed with respect to O&M expenses, for
15 recognizing that there is no provision included for extraordinary or one time events
16 which may increase capital requirements for the future.
- 17 Q. Have you projected capacity factors for the Company's nuclear units?
- 18 A. Yes. As shown in Exhibit RED-5, we expect capacity factors to improve over the
19 next several years due to the improvements I discussed earlier.
- 20 Q. Are these projections reasonable?
- 21 A. Yes. Although they are very aggressive, these capacity factors are reasonable in light
22 of past experience, industry averages, regulatory requirements, and planned operating
23 improvements.

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

3 A. Yes it is.

4 Q. Does this conclude your direct testimony?

5 A. Yes it does.

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

<u>Year</u>		<u>Beaver Valley Unit 1</u>	<u>Beaver Valley Unit 2</u>	<u>Total Beaver Valley</u>	<u>Perry Nuclear Power Plant</u>	<u>Total All Units</u>
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

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

<u>Year</u>		<u>Beaver Valley Unit 1</u>	<u>Beaver Valley Unit 2</u>	<u>Total Beaver Valley</u>	<u>Perry Nuclear Power Plant</u>	<u>Total All Units</u>
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

Duquesne Light Company
Nuclear Capital Costs
(millions of dollars)

<u>Year</u>		<u>Beaver Valley Unit 1</u>	<u>Beaver Valley Unit 2</u>	<u>Total Beaver Valley</u>	<u>Perry Nuclear Power Plant</u>	<u>Total All Units</u>
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

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

<u>Year</u>		<u>Beaver Valley Unit 1</u>	<u>Beaver Valley Unit 2</u>	<u>Total Beaver Valley</u>	<u>Perry Nuclear Power Plant</u>	<u>Total All Units</u>
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-5Duquesne Light Company
Nuclear Capacity Factors

<u>Year</u>		<u>Beaver Valley Unit 1</u>	<u>Beaver Valley Unit 2</u>	<u>Perry Nuclear Power Plant</u>
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

VOLUME IV

Duquesne Statement No. 12

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104**

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

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**

1 I. INTRODUCTION

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

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

7 Q. Please describe your academic background.

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

14 Q. Please describe your work experience.

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

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

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

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

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

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

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

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

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

26 These four sources of subjectivity create a regulatory atmosphere in which it is very difficult, if
27 not impossible, to resolve the contentious issues surrounding the setting of the fair rate of return.
28 Most, if not all, other issues in rate cases have objective standards (*e.g.*, legal, policy, empirical)

1 upon which to measure the value of evidence presented in rate cases. Only the process of finding
2 the fair rate of return seems immune to measurement by such standards.¹

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

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

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

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

23 The markets for utility securities provide the best (and indeed the only) evidence on what
24 investors require as a return on the money they invest in utilities, and the financial models that
25 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.

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

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

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

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

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

20 Q. Why is a forward-looking perspective important?

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

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

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

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

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

26 This indeed is the practical criterion that separates the usefulness of the two most popular
27 financial theories used in rate cases—the DCF and the CAPM. The DCF renders a cost of
28 capital estimate for each company in a proxy group. Some might seem a bit high and others a
29 bit low, but the individual company results have objective “measures of central tendency,” such
30 as means and medians. This is not true for the CAPM. The CAPM is the sum of two

1 components: (1) a company-specific risk premium; and (2) a “risk-free” rate applicable to all
2 companies. There is a wide variety of risk-free rates from which to choose (*e.g.*, long-
3 term/short-term) for which theory gives us no unambiguous guide. Furthermore, because the
4 same risk-free rate applies as an additive term to all companies’ cost of equity estimates, there
5 is no measure of central tendency in the result. In short, we cannot resolve the question of
6 uncertainty surrounding short-term versus long-term rates by repeated sampling. In the end,
7 the analyst has to choose a risk-free rate that drives the results—precisely the type of choice
8 that limits the model’s objectivity and effectiveness. Indeed, this is the principal reason I avoid
9 the CAPM as a primary ROE method in cases where it has not been deemed a required element
10 of rate filings.

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

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

21 **II. SUMMARY AND BACKGROUND TO THE DETERMINATION OF A FAIR RATE** 22 **OF RETURN ON EQUITY**

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

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

26 A. The fair rate of return on equity that I recommend for Duquesne is **11.65 percent**. My
27 recommendation results from a DCF analysis performed on a proxy group of U.S. electric
28 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.)

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

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

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

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

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

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

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

23 Q. Please explain.

24 A. Deregulation has been implemented in many industries throughout many countries in the past
25 20 years. The electric industry has not been immune to these changes. Technological changes,
26 increased competitive pressures, and low fuel costs have made deregulation a possibility in the
27 industry and successful deregulation in other industries has created demand for it.

28 Most states have begun the process of inquiring how the electric industry within its borders can
29 be restructured; a few are well on their way. In its Electricity Generation Customer Choice
30 and Competition Act, Pennsylvania has declared that electricity generation can be opened to
31 competition while transmission and distribution must remain regulated. How this will be

1 implemented and how issues such as stranded costs will be dealt with will be addressed in this
2 proceeding. One point to keep in mind, however, is that notwithstanding the change in the
3 nature of electricity regulation in Pennsylvania, the Act is consistent with the traditional
4 regulatory compact insofar as it allows Duquesne and the other electric utilities the opportunity
5 to recover the opportunity cost of the capital devoted to regulated activities.

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

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

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

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

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

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

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

26 A. Fixed payment obligations accompany both debt and preferred stock: interest on the former,
27 preferred dividends on the latter. It is not a difficult task to calculate the dollars needed to
28 cover interest or preferred stock dividend payments either currently or over the period of time

1 in which the rates in question for a utility will be in effect. The *embedded* cost of debt and
2 preferred stock proceeds directly from these calculations.

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

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

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

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

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

25 A. No. An essential component to that calculation was knowledge of the (fixed) interest and
26 preferred stock dividend payments. Dividend payments on common stock equity are not fixed,
27 nor is their growth rate measured with certainty. They are generally expected to grow as the
28 company in question grows. This growth rate is not observable—the growth rate is embodied
29 in unobservable equity investor expectations regarding the future performance of the company

1 in question. Because this growth rate is not observable, the future stream of dividend payments
2 is not known. There is therefore no known stream of payments that may be used directly to
3 find the discount rate equating the present value of the future stream of dividend payments with
4 the observed common stock price.

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

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

16 C. Estimating the Cost of Equity Capital

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

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

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

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

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

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

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

14 **III. THE DCF METHOD**

15 **A. Description of the DCF Method**

16 Q. Please describe the DCF method.

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

1 The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models,
 2 which was first published in complete form in 1962.² The research performed by subsequent
 3 writers (including Gordon himself) resulted in the equation known as the "Periodic" DCF model.
 4 The "Periodic" DCF model generally expresses k_e , the cost of the common stock equity portion
 5 of total capital, as a relationship between the prevailing price of common stock equity, P_0 ,
 6 current dividends, D_0 , and the dividend growth rate, g . Following is a formal statement of the
 7 "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 = $D_0 * (1 + g)$

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

14 A different version of the DCF model avoids these abstractions. Specifically, the "Quarterly"
 15 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.

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

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

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

11 Q. Please explain the difference.

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

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

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

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

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

6 **B. Selection of Comparable Company Group**

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

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

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

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

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

24 A. Circular reasoning has long been found to be a serious problem in the determination of a fair
25 rate of return for investors. For example, the principle of "fair value" rate regulation (which
26 dominated public utility regulation at both the state and Federal level before the 1940s) gave
27 way to "cost-based" rate regulation in large part because of a problem of circularity. As
28 Professor Bonbright stated: "Any attempt to test the fairness of the rates by reference to a

1 valuation of the properties (which depends on rates themselves) is an attempt to reason in a
2 circle, or, if you like, to put the cart before the horse.”⁴

3 Whenever a commission uses a formula for determining a fair return that depends on investors’
4 expectations of future growth, circularity arises because we know that investors’ expectations
5 depend on the return that the regulator is expected to allow. The path of supposed causation
6 proceeds in *both directions simultaneously*, which, of course, is the source of circular reasoning.

7 Another example of the circularity problem in the determination of the fair rate of return is the
8 practice of using other public utilities’ returns in a “comparable earnings” analysis. If the past
9 earnings of the comparable group are low, it will likely result in a lower awarded rate of return on
10 equity for the company under consideration. This company will, in turn, become part of another
11 comparable group and will contribute to lower rates of return for other companies, creating a
12 cycle from which it is difficult to escape.

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

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

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

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

23 Q. What criteria did you use to determine that the companies you chose are “comparable” to
24 Duquesne’s electric operations?

25 A. I defined what I conclude are the minimum number of criteria that would satisfy two basic
26 objectives. The first basic objective was to assemble a group of companies with publicly-
27 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.

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

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

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

9 Given these characteristics, I used two criteria to exclude companies from the proxy group.
10 *First*, I selected those companies that derived at least 85 percent of operating revenues from
11 electricity sales. The average proportion of total operating revenue from electric activity in
12 1996 for the proxy group was 95.4 percent. Duquesne derived 100 percent of its operating
13 revenues from electric activities. *Second*, I restricted the group of companies to those with a
14 total capital less than \$10.0 billion. Some of the utilities in the proxy group have a higher total
15 capital than Duquesne and some a lower total capital, but my goal (as stated above) was to
16 create a proxy group that, *on average*, is representative of the business risk faced by Duquesne.
17 The average total capital for the group was almost \$3.5 billion and Duquesne's was about \$3.1
18 billion.

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

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

1 associated with takeovers generally affect stock prices in a temporary way unrelated to the
 2 overall cost of capital and make the use of those stock prices in a DCF analysis suspect.

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

4 A. Yes.

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

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

8 Q. Please summarize the criteria you selected.

9 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.

10 Q. What was the result of applying your criteria?

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

13 C. Inputs into the DCF Calculations

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

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

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

22 1. Calculation of the Stock Price, P_0

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

24 A. I used stock prices obtained from the *Wall Street Journal*. It is my normal practice to use stock
25 prices on the latest day consistent with the filing, because only the latest stock prices are
26 consistent with up-to-date investors expectations. This is because the informative value (with
27 regard to investor expectations) of yesterday's stock prices will be completely superseded by
28 today's stock prices. This is a widely held tenet of efficient markets. If today's stock prices

1 embody all of the expectations regarding the value of those stocks, then yesterday's prices
2 represent "old news." Yesterday's prices, therefore, are useless as a gauge to investors' current
3 expectations.

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

11 Q. Did you adjust the observed stock prices?

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

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

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

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

1 stock prices, are observed to drop by an amount approximately equal to the quarterly dividend
2 on the ex-dividend date.⁵

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

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

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

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

19 Q. Why do you reference New York?

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

23 Q. Should the adjustment should be performed in Pennsylvania?

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.

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

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

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

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

19 **2. Calculation of the Dividend D_1**

20 Q. How did you measure the dividend, D_1 ?

21 A. The DCF model requires that $D_1 = D_0 * (1 + g)$, where D_0 is equal to the sum of the four
22 most recent dividend payments. Thus, my starting point was to obtain the data for D_0 . I
23 obtained the sum of the past four quarterly dividend per share payments from *Value Line*
24 *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.

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

3 3. Calculation of Growth, g

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

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

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

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

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

$$g = B * R + S * V$$

Where:

(2)

B = expected retention ratio

R = expected return on equity

S = percent new equity expected

V = 1 - book to market ratio

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

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

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

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

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

21 A. They are reasonable in the context of proceedings in which rate of return is being examined. It
22 would be naïve to assume that the growth rates forecasted by *Value Line* are applicable far into
23 the future. However, there are two strong reasons for employing such forecasts in the present
24 proceeding. First, to the extent that investors employ forecasts like those published by *Value*
25 *Line* as long-term growth rates, these forecasts accurately reflect the current expectations of
26 long-term growth included in the cost of capital. Second, *Value Line* forecast growth rates may
27 not be substantially different, on average, from what investors believe long-term growth
28 prospects to be, given that the forecast is widely distributed in the financial community. In

1 addition, a study by Brown and Rozeff shows that *Value Line* analysts make better forecasts
2 than could be obtained by employing historical data only.⁸

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

4 4. Selling and Issuance Cost Adjustment

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

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

8 Q. Why did you make such an adjustment?

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

18 Q. Is such an adjustment generally made by regulators?

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

22 Q. Please explain.

23 A. Basing required returns on net, rather than gross, proceeds is standard regulatory practice when
24 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.

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

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

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

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

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

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

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

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

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

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

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

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

14 A. It is proper to include an issuance expense return adjustment for the entire equity component of
15 the capital structure.⁹ Therefore, I used the conventional form of the issuance expense
16 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.

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

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

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

20 **D. Empirical DCF Calculations for Proxy Group of Electric Companies**

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

22 A. Using the ex-dividend date adjusted stock prices for a 52-week closing average, ending July 18,
23 1997, the most recent four actual dividend per share payments, the average of the sustainable
24 growth and forecast earnings growth, and the issuance cost method shown above, I estimated a
25 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.

1 **IV. REASONABLENESS CHECK**

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

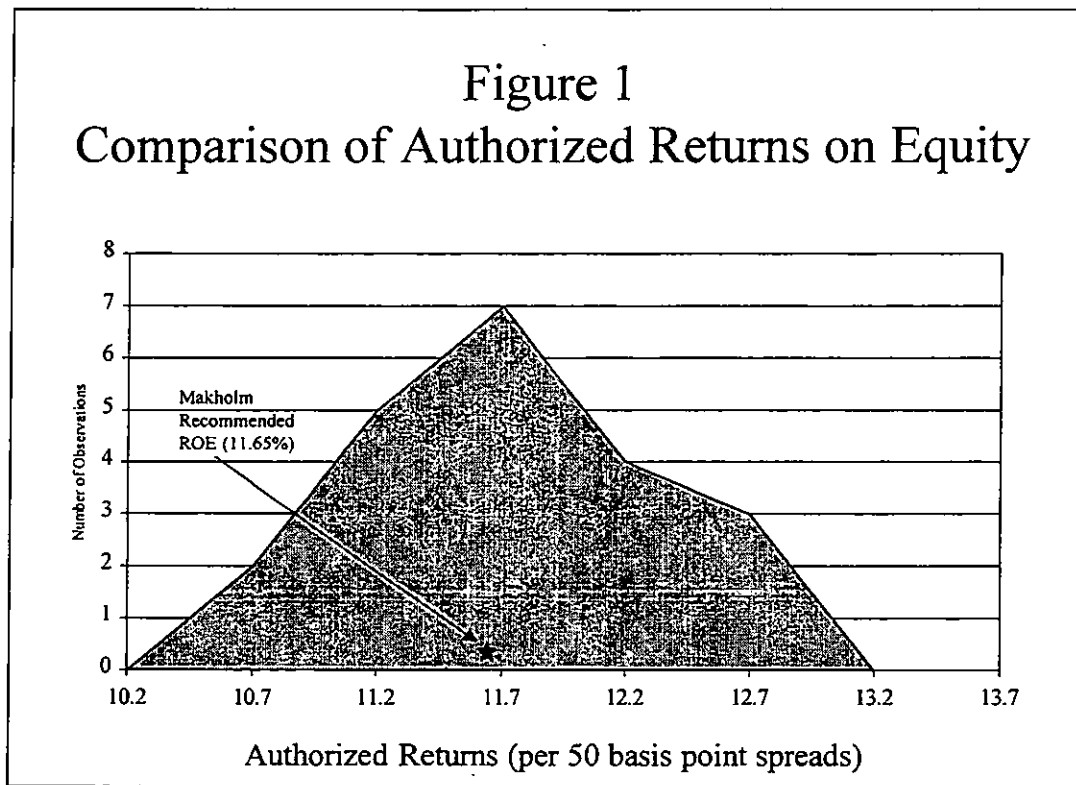
4 A. Yes.

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

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

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

9 A. **Figure 1** shows the range of electric utilities' returns on equity which have been authorized by
10 regulatory commissions throughout the country between April 1995 and March 1997. My data
11 base covers a total of 23 decisions. The figure also shows the number of decisions associated
12 with each return on equity figure. I have indicated where my recommended return on equity of
13 **11.65 percent** falls within the range of ROEs. **Exhibit JDM - 12** presents the individual state
14 commissions' allowed returns that make up the figure.



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

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

5 V. MARKET TO BOOK RATIOS

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

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

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

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

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

6 A. No.

7 Q. Why not?

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

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

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

25 Relaxing these assumptions drives a wedge between the market value and book value of
26 common stock equity. Seeing that these conditions are highly unrealistic in practice, there is
27 no reason to expect that, even on average, stock prices should equal book values for common

1 equity. In fact, relaxing these assumptions, as explained in **Exhibit JDM - 13**, has a greater
2 upward effect on expected earnings than downward, except in periods of high inflation
3 combined with regulatory lag, as occurred in the late 1970s to early 1980s.

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

10 VI. STRANDED COST RECOVERY

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

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

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

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

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

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

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

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

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

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

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

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

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

1 derision on the part of the Administrative Law Judge involved—reasonable evidence that its
2 equity capital costs had reached speculative levels.¹²

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

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

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

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

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

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

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

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

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

24 Q. Please explain your latter point.

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

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

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

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

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

9 A. Yes.

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

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

15 Q. What are the study's conclusions?

16 A. The main conclusions are as follows:

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

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

24 Q. Do you agree with these conclusions?

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

27 Q. Please describe the methodology of the study.

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

8 Q. What is the rationale for the use of “holding periods”?

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

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

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

21 A related problem is that so far as I can tell the NARUC study’s average internal rates of return
22 are derived by straight averaging rather than weighted averaging. That is, in forming their final
23 results the NARUC authors appear to have taken a simple average of their results for all 171
24 holding periods they studied, rather than accounting for the fact that the holding periods should
25 be weighted proportionally to their duration. Simple averaging is an incorrect approach
26 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.

1 returns earned over a 20 year holding period. If the return on a stock was 15% from 1972 to
2 1975 and 5% from 1972 to 1992, the NARUC methodology would produce a return of 10% for
3 the stock—clearly a wrong result.

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

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

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

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

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

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

23 • Method II ("Basic Rate of Return") ranked DQE 85 out of the 97 utilities, with a basic rate
24 of return of 8.69% as compared to the utility average of 11.14% and the S&P 400 average
25 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.

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

4 Q. Do you believe the NARUC analysis is valid?

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

8 Q. Can you recommend an alternative to the NARUC “holding period” analysis?

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

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

18 Q. What are the results of your analysis?

19 A. My internal rate-of-return analysis reveals that for electric utilities the average internal rate of
20 return from 1972 to 1992 was 9.51% while the return for the S&P Industrials was 10.20% and
21 for the S&P Utilities was 10.99%. When I applied the same analysis to the period from 1972 to
22 1996, I found that the internal rate of return for electric utilities declined to 9.44%, while the
23 internal rates of return for the S&P Industrials and the S&P Utilities grew to 10.49% and
24 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.

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

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

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

14 VII. CONCLUSION

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

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

18 Q. Does this conclude your direct testimony?

19 A. Yes.

**VITA
OF
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Dr. Makhholm has directed projects on regulation, pricing, financing, and development for dozens of privately-owned and government-owned gas, electric and telecommunication utilities and other businesses in the United States and in 19 other countries. In the United States, Dr. Makhholm has represented a large number of utilities, either individually or in groups, as well as interstate gas pipeline companies and gas producers, in Federal and State regulatory proceedings on all aspects of tariffs, regulation, planning, competition and restructuring. Abroad, he has assisted utilities, governments and the World Bank. He has derived tariffs in many of these countries, written regulatory laws, proposed financing plans and assisted in the pre-privatization restructuring of utilities.

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
PROVIDENCE, RHODE ISLAND
Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

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

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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.)

REGULATORY AND GOVERNMENT

Delaware Public Service Commission

re: Delmarva Power & Light Company

District of Columbia Public Service Commission

re: Potomac Electric Power Company
Washington Gas Light Company

Massachusetts Municipal Wholesale Electric Company

The Government of Chile

Gas industry regulations

The Government of Argentina

Plan for privatized rail freight industry regulation

The Government of Tanzania

Natural gas development and regulation plan for Songo Songo Island gas reserves.

Financing the development of gas reserves on Songo Songo Island with emphasis on payment guarantee mechanisms for foreign exchange.

The World Bank

re: Natural gas tariffs for Polskie Gornictwo Naftowe i Gazownictwo
(The Polish Oil and Gas Company)

re: Natural gas transport and distribution tariffs for Gas del Estado
(The Argentine State-owned gas utility)

re: Natural gas development for the Moroccan Gas System.

re: Natural gas transport and distribution tariffs for the Bolivian Gas Industry.

re: Natural gas development plan for Sichuan province of China.

OTHER

Air New Zealand

Centel Corporation

General Electric Company

Intel Corporation

Jamaica Water Supply Company

Nucor Steel Corporation

Parsons Brinckerhoff Development Group

MEMBERSHIP IN

PROFESSIONAL ORGANIZATIONS

The American Economic Association

March 1997

n/e/r/aNational Economic Research Associates, Inc.
Consulting Economists**topics***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.

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

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

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.

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

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

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

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.

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

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.

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,

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

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.

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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:

$$P_0 = \text{price of stock} \quad (2.1)$$

$$D_0 = \text{last dividend}$$

$$k_e = \text{cost of equity}$$

$$g = \text{growth rate of dividends}$$

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

$$k_e = \frac{D_0}{P_0} + g \quad (2.2)$$

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:

$$P_0 = \frac{D_1}{(1+k_e)} + \frac{D_2}{(1+k_e)^2} + \dots + \frac{D_n}{(1+k_e)^n} + \dots$$

where:

$$P_0 = \text{current stock price} \quad (2.3)$$

$$D_1, \dots, D_n = \text{last dividend}$$

If dividends are assumed to grow at a constant growth rate, g , we can rewrite equation (2.3) as:

$$P_0 = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \dots + \frac{D_0(1+g)^n}{(1+k_e)^n} + \dots$$

where:

$$D_0(1+g) = D_1 \quad (2.4)$$

$$D_0 = \text{last dividend payment}$$

Equation (2.4) can be solved for k_e to obtain:

$$k_e = \frac{D_0(1+g)}{P_0} + g. \quad (2.5)$$

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:

$$P_0 = D_{0.4} \frac{(1+g)^{25}}{(1+k_e)^{25}} + D_{0.4} \frac{(1+g)^{50}}{(1+k_e)^{50}} + D_{0.4} \frac{(1+g)^{75}}{(1+k_e)^{75}} + \dots$$

where:

$$D_{0.4} = \text{last quarterly dividend payment} \quad (2.6)$$

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).

$$P_0 = \frac{D_{01}(1+g)}{(1+k_e)^{25}} + \frac{D_{02}(1+g)}{(1+k_e)^5} + \frac{D_{03}(1+g)}{(1+k_e)^{75}} + \frac{D_{04}(1+g)}{(1+k_e)^{1.00}} +$$

$$\frac{D_{01}(1+g)^2}{(1+k_e)^{1.25}} + \frac{D_{02}(1+g)^2}{(1+k_e)^{1.5}} + \frac{D_{03}(1+g)^2}{(1+k_e)^{1.75}} + \frac{D_{04}(1+g)^2}{(1+k_e)^{2.00}} + \quad (2.7)$$

$$\frac{D_{01}(1+g)^3}{(1+k_e)^{2.25}} + \frac{D_{02}(1+g)^3}{(1+k_e)^{2.5}} + \dots$$

where:

$$D_{01}, \dots, D_{04} = \text{last four previous quarterly dividend payments.}$$

This model is a more accurate extension of equation (2.6). The DCF formula presented as equation (2.7) can be reduced to:

$$k_e = \frac{D_{01}(1+k_e)^{75} + D_{02}(1+k_e)^5 + D_{03}(1+k_e)^{25} + D_{04}}{P_0} (1+g) + g \quad (2.8)$$

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:

$$\frac{D_{01}[(1+k_e)^{75} - 1] + D_{02}[(1+k_e)^5 - 1] + D_{03}[(1+k_e)^{25} - 1]}{P_0} (1+g) \quad (2.9)$$

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:

$$D_1 = D_0(1+g) \quad (2.10)$$

$$= [D_{01} + D_{02} + D_{03} + D_{04}](1+g)$$

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

<u>Company</u>	<u>Total Capitalization</u> ---(\$ Million)---	<u>Revenue from Electricity</u> ---(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.	IES Industries
American Electric Power Co., Inc.	Illinova Corp.
Atlantic Energy, Inc.	Interstate Power Co.
Baltimore Gas & Electric Co.	IPALCO Enterprises, Inc.
Black Hills Corp.	Kansas City Power & Light Co.
Boston Edison Co.	KU Energy Corp.
Carolina Power & Light Co.	LG&E Energy Corp.
Central Hudson Gas & Electric Corp.	Long Island Lighting Co.
Centerior Energy Corp.	MDU Resources Group, Inc.
Central and South West Corp.	MidAmerican Energy Holdings Co.
Central Louisiana Electric Co., Inc.	Minnesota Power & Light Co.
Central Maine Power Co.	Montana Power Co.
Central Vermont Public Service Corp.	Nevada Power Co.
CILCORP Inc.	New England Electric System
Cinergy Corp.	New York State Electric & Gas Corp.
CIPSCO, Inc.	Niagara Mohawk Power Corp.
CMS Energy Corp.	NIPSCO Industries, Inc.
Commonwealth Energy System	Northeast Utilities
Consolidated Edison Co.	Northern States Power Co.
Delmarva Power & Light Co.	Northwestern Public Service Co.
Dominion Resources, Inc.	OGE Energy Corp.
DPL Inc.	Ohio Edison Co.
DTE Energy Co.	Orange & Rockland Utilities, Inc.
Duke Power Co.	Otter Tail Power Co.
DQE	PacifiCorp
Eastern Utilities Associates	PECO Energy Co.
Edison International	PG&E Corp.
Empire District Electric Co.	Pinnacle West Capital Corp.
Enova Corp.	Portland General Corp.
Entergy Corp.	Potomac Electric Power Co.
Florida Progress Corp.	PP&L Resources, Inc.
FPL Group, Inc.	Public Service Co. of New Mexico
GPU, Inc.	Public Service of Colorado
Green Mountain Power Corp.	Public Service Enterprise Group, Inc.
Hawaiian Electric Industries, Inc.	Puget Sound Energy, Inc.
Houston Industries Inc.	Rochester Gas & Electric Corp.
Idaho Power Co.	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.	Southern Company
Edison International	Texas Utilities Co.
Entergy Corp.	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	Interstate Power Co.
American Electric Power Co., Inc.	Kansas City Power & Light Co.
Atlantic Energy, Inc.	Ohio Edison Co.
Centerior Energy Corp.	Portland General Corp.
Central Louisiana Electric Co., Inc.	Potomac Electric Power Co.
Delmarva Power & Light Co.	Southwestern Public Service Co.
Duke Power Co.	TECO Energy, Inc.
DQE	Union Electric Co.
Houston Industries Inc.	

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.	New York State Electric & Gas Corp.
Central Maine Power Co.	Niagara Mohawk Power Corp.
Central Vermont Public Service Corp.	Northeast Utilities
FPL Group, Inc.	Pinnacle West Capital Corp.
IPALCO Enterprises, Inc.	TNP Enterprises Inc.
New England Electric System	Tucson Electric Power Co.

After all those companies were eliminated, the following 17 companies remain in the proxy group:

Carolina Power & Light Co.	KU Energy Corp.
Central and South West Corp.	Minnesota Power & Light Co.
Cinergy Corp.	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.

FILE

CONTINUED