STATE OF TENNESSEE

Office of the Attorney General

PAUL G. SUMMERS
ATTORNEY GENERAL AND REPORTER

ANDY D. BENNETT
CHIEF DEPUTY ATTORNEY GENERAL

LUCY HONEY HAYNES
ASSOCIATE CHIEF DEPUTY
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P.O. BOX 20207
NASHVILLE, TN 37202

MICHAEL E. MOORE
SOLICITOR GENERAL

CORDELL HULL AND JOHN SEVIER
STATE OFFICE BUILDINGS

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Reply to:
Consumer Advocate and Protection Division
Attorney General's Office
P.O. Box 20207
Nashville, TN 37202

April 16, 2003

Hon. Sara Kyle, Chairman
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Responses by the Consumer Advocate and Protection Division of the Office of the Attorney General toTennessee American Water Company's Initial Request for Discovery, Docket No. 03-00018

Dear Chairman Kyle:

Enclosed is an original and fourteen copies of the Consumer Advocate and Protection Division's Responses to the Initial Request for Discovery in the Petition of Tennessee American Water Company to Change and Increase Certain Rates and Charges so as to Permit it to Earn a Fair and Adequate Rate of Return on its Property Used and Useful in Furnishing Water Service to its Customers. Copies are being furnished to counsel of record for interested parties.

Sincerely,

Vance Broemel

VANCE BROEMEL,
Assistant Attorney General

cc: Counsel of Record
52476

IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)
	)
PETITION OF TENNESSEE AMERICAN WATER COMPANY TO CHANGE AND INCREASE CERTAIN RATES AND CHARGES SO AS TO PERMIT IT TO EARN A FAIR AND ADEQUATE RATE OF RETURN ON ITS PROPERTY USED AND USEFUL IN FURNISHING WATER SERVICE TO ITS CUSTOMERS	) DOCKET NO. 03-00118

RESPONSES BY THE CONSUMER ADVOCATE AND PROTECTION DIVISION OF THE OFFICE OF THE ATTORNEY GENERAL TO TENNESSEE AMERICAN WATER COMPANY'S INITIAL REQUEST FOR DISCOVERY

Comes Paul G. Summers, the Attorney General & Reporter, through the Consumer Advocate and Protection Division of the Office of Attorney General (hereinafter "CAPD" or "Consumer Advocate") and hereby responds to the discovery requests propounded upon the Consumer Advocate by Tennessee American Water Company ("TAWC" or "Tennessee-American Water").

DISCOVERY REQUEST NO. 1:

State in detail the legal and factual basis for any objection or opposition CAPD has with respect to any aspect of the rate increase requested by TAWC in this docket.

RESPONSE NO. 1:

Without waiving its previous objections, the CAPD would respond as follows: Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. However, a preliminary review of the rate filing by Tennessee-American Water reveals the following defects:

(1) The petitioner appears to contravene the Tennessee Regulatory Authority's order of Jan. 11, 2000, in Docket No. 99-00891: *Tennessee-American Tariff filing to Reduce the Fire Hydrant Annual Charge as a Part of a Settlement Agreement Between the City of Chattanooga and Tennessee-American Water Company.* In that docket the company reduced its fire hydrant revenue by $1.1 million when the Tennessee Regulatory Authority approved the company's proposal to reduce fire hydrant rates from $301.50 to $50. The Authority conditioned its approval as follows:

> CHAIRMAN MALONE: It seems that the company has represented that it will not in the future seek to recover lost revenue in a rate case from the ratepayer. With those responses, it would be my inclination and I would move that we approve the tariff, but that in so doing, we order that the allocation of the lost revenue be to the stockholders and not to the ratepayers whether now or at such later time in the future.
>
> DIRECTOR KYLE: I vote yes. I'm in favor of approving the Tennessee-American Water Company Tariff Filing to reduce the fire hydrant charges with a revenue loss allocated to the stockholders.

The petitioner's filing appears to violate the Authority's order as shown by Company witness Miller statement in his direct testimony at page 11:

> Q. What is the level of public fire service cost of service that has been allocated to other revenue classifications in this case?
>
> A. As indicated in Mr. Herbert's cost of service study, the company has allocated

$1.105 million ...to other customer classes.

(2) The petitioner's requested rate of return on equity appears to lack support; the petitioner's requested rate of return on debt appears to lack support; the petitioner's cost-of-service study appears to lack support; the petitioner's test year and attrition period expenses and revenues appear to lack support.

Finally, the CAPD reserves its right to add to or amend its objections or opposition to the rate filing by Tennessee-American Water at the time the CAPD files its pre-filed testimony.

DISCOVERY REQUEST NO. 2:

Identify each person whom you expect to call as an expert witness at any hearing in this docket, and for each such expert witness:

(a) identify the field in which the witness is to be offered as an expert;

(b) provide complete background information, including the expert's current employer as well as his or her educational, professional and employment history, and qualifications within the field in which the witness is expected to testify, and identify all publications written or presentations presented in whole or in part by the witness;

(c) provide the grounds (including without limitation any factual bases) for the opinions to which the witness is expected to testify, and provide a summary of the grounds for each such opinion;

(d) identify any matter in which the expert has testified (through deposition or otherwise) by specifying the name, docket number and forum of each case, the dates of the prior testimony and the subject of the prior testimony, and identify the transcripts of any such testimony;

(e) identify for each such expert any person whom the expert consulted or otherwise communicated with in connection with his expected testimony;

(f) identify the terms of the retention or engagement of each expert including but not limited to the terms of any retention or engagement letters or agreements relating to his/her engagement, testimony and opinions;

(g) identify all documents or things shown to, delivered to, received from, relied upon, or prepared by any expert witness, which are related to the witness(es)' expected testimony, including without limitation all documents or things provided to that expert for review in connection with testimony and opinions; and

(h) identify any exhibits to be used as a summary of or support for the testimony or opinions provided by the expert.

RESPONSE NO. 2:

Without waiving its previous objections, the CAPD would respond as follows:

Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. However, after a preliminary review of the rate filing by Tennessee-American Water, the CAPD may call the following expert witnesses:

(a) Dr. Stephen Brown, Mark Crocker, CPA, Michael Chrysler, and Dan McCormac, CPA. Brown - Cost of Capital; Cost of Service; TRA Order in Docket No. 99-00891. Crocker & Chrysler: Expenses, Revenues, Rate Base. McCormac: Undetermined at this time and dependent upon further review of discovery material.

(b) Resumes and publications attached.

(c) See Response to Discovery Request 1.

(d) Appearances before the Tennessee Regulatory Authority:

Brown: Docket No. 01-00868 *XO Tennessee, Inc. Complaint of XO Tennessee, Inc. Against BellSouth Telecommunications, Inc;* Brown: Docket No.*00-00562 United Cities Gas Company Petition for Approval of Various Franchise Agreements*; Docket No. 01-00704 *Tennessee Regulatory Authority United Cities Gas Company's Incentive Plan Account (IPA) for the period of April 1, 2000 through March 31, 2001;*

Chrysler: Docket No. 02-00383 *Chattanooga Gas Company Petition of Chattanooga Gas Co. for Approval of Change in Purchase Gas Adjustment.*

McCormac: numerous dockets and cases since 1976

(e) CAPD's attorneys.

(f) Employees of the State of Tennessee.

(g) The petitioner's filing, the TRA's order in Docket No. 99-00891, and other documents to be determined.

(h) Undetermined at this time. This material will be generated at a later stage of this proceeding.

The CAPD reserves the right to alter or amend its witnesses and their scope of testimony and exhibits in light of ongoing discovery and investigation.

DISCOVERY REQUEST NO. 3:

Please provide copies of any and all documents referred to or relied upon in responding to

TAWC's discovery requests.

<u>RESPONSE NO. 3</u>:

Without waiving its previous objections, the CAPD would respond as follows: Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. However, the CAPD would state that at this time it has relied on the material referred to in the response to 1(g).

<u>DISCOVERY REQUEST NO. 4</u>:

Please provide all material provided to, reviewed by or produced by any expert or consultant retained by CAPD to testify or to provide information from which another expert will testify concerning this case.

<u>RESPONSE NO. 4</u>:

Without waiving its previous objections, the CAPD has not retained outside experts regarding this matter.

<u>DISCOVERY REQUEST NO. 5</u>:

Please produce all work papers of any of CAPD's proposed experts, including but not limited to file notes, chart notes, test results, interview and/or consult notes and all other file documentation that any of CAPD's expert witnesses in any way used, created, generated or consulted by any of CAPD's expert witnesses in connection with the evaluation, conclusions and opinion in the captioned matter.

<u>RESPONSE NO. 5</u>:

Without waiving its previous objections, the CAPD would respond as follows: Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. Accordingly, all work papers to be relied upon by its experts have not yet been determined.

DISCOVERY REQUEST NO. 6:

Please produce a copy of all trade articles, journals, treatises and publications of any kind in any way utilized or relied upon by any of CAPD's proposed expert witnesses in evaluating, reaching conclusions or formulating an opinion in the captioned matter.

RESPONSE NO. 6:

Without waiving its previous objections, the CAPD would respond as follows: Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. Accordingly, all trade articles, etc. to be relied upon by its experts have not yet been determined.

DISCOVERY REQUEST NO. 7:

Please produce a copy of all documents which relate or pertain to any factual information provided to, gathered by, utilized or relied upon by any of CAPD's proposed expert witnesses in evaluating, reaching conclusions or formulating an opinion in the captioned matter

RESPONSE NO. 7:

See response to Discovery Request 6.

DISCOVERY REQUEST NO. 8:

Please produce a copy of all articles, journals, books or speeches written by or co-written by any of CAPD's expert witnesses, whether published or not.

RESPONSE NO. 8:

See Attached.

DISCOVERY REQUEST NO. 9:

Please produce any and all documentation, items, reports, data, communications, and evidence of kind that CAPD intends to offer as evidence at the hearing or to refer to in any way at the hearing.

RESPONSE NO. 9:

Without waiving its previous objections, the CAPD would respond as follows: Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. Accordingly, all documentation, etc. intended to be offered as evidence has not yet been determined.

DISCOVERY REQUEST NO. 10:

Please produce all documents that refer or relate to the subject matter of your response to Discovery Request No. 1.

RESPONSE NO. 10:

Without waiving its previous objections, the CAPD would respond as follows: Investigation into this case by the CAPD is still proceeding; in particular, the CAPD has not yet received responses to its first set of discovery requests to Tennessee-American Water. Accordingly, all documents that refer or relate to the subject matter have not yet been determined. However, at this time, the CAPD has reviewed the petitioner's filing in the instant docket and the TRA's order in Docket No. 99-00891.

DISCOVERY REQUEST NO. 11:

Please identify by name, address, employer, and current telephone number, all persons having knowledge of the subject matter of your response to Discovery Request No. 1.

RESPONSE NO. 11:

The witnesses listed herein and CAPD's attorneys : 615-741-8733 (Vance Broemel) or 615-532-3382 (Shilina Chatterjee).

RESPECTFULLY SUBMITTED,

Vance L. Broemel

VANCE L. BROEMEL, B.P.R. #11421
Assistant Attorney General
Office of the Attorney General
Consumer Advocate and Protection Division
(615) 741-8733

Shilina B. Chatterjee

SHILINA B. CHATTERJEE, B.P.R. #20689
Assistant Attorney General
Office of the Attorney General
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, Tennessee 37202
(615) 532-3382

Dated: April 16, 2003

CERTIFICATE OF SERVICE

I hereby certify that a true and exact copy of the foregoing has been forwarded by first-class mail, postage prepaid, to the following:

R. Dale Grimes, Esq.
Bass, Berry & Sims, PLC
Amsouth Center
315 Deaderick Street, Suite 2700
Nashville, TN 37238-3001

Michael A. McMahan, Esq.
Phillip A. Noblett, Esq.
Lawrence W. Kelly, Esq.
Nelson, McMahan & Noblett
801 Broad Street, Suite 400
Chattanooga, TN 37402

Henry M. Walker, Esq.
Boult, Cummings, Conners & Berry, PLC
414 Union Street, Suite 1600
Nashville, TN 37219

David C. Higney, Esq.
Grant, Konvalinka & Harrison, P.C.
633 Chestnut Street, 9th Floor
Chattanooga, TN 37450

Vance L. Broemel

VANCE L. BROEMEL
Assistant Attorney General

Discovery Request Response 2B

Stephen N. Brown

Employment History & Education

Economist - Consumer Advocate & Protection Division, Office of the Attorney General, State of Tennessee, Nashville TN. ('6/99-Current) Expert witness on economic conditions for telecommunications and gas utilities. Prepared direct and rebuttal testimony on rate-of-return and economic incentive plans in many cases held before the Tennessee Public Service Commission and Tennessee Regulatory Authority. Wrote hundreds of Excel Visual Basic programs and developed many formats and procedures used in rate cases.

Director, Public and Technology Policy - New World Paradigm, Ltd. Arlington VA. ('6/98- 5/99) The company develops new communications and video technologies for the private sector. I prepare press releases, arrange meetings between company personnel and members of the executive and legislative branches of the federal government and direct company filings before the Federal Communications Commission. Docketed proceedings where I have directed filings include Common Carrier Docket 98-146, Telecommunications Infrastructure for the 21st Century, Common Carrier Docket 98-147, Rulemaking for the delivery of data services by local telephone companies, and Cable Services Docket 98-120, the delivery of broadcast digital TV signals over cable TV systems.

Senior Economist - Consumer Advocate Division, Office of the Attorney General, State of Tennessee, Nashville TN. ('3/95-'6/98) Expert witness on economic conditions for telecommunications and gas utilities. Prepared direct and rebuttal testimony on rate-of-return and economic incentive plans in many cases held before the Tennessee Public Service Commission and Tennessee Regulatory Authority. Wrote hundreds of Excel Visual Basic programs and developed many formats and procedures used in rate cases.

Treasurer and Trustee, Automatic Meter Reading Association (AMRA). ('90-'94) An international organization of 600 members developing markets and standards for wireless and landline communication for automatic and remote access to all electric, gas, and water meters. Regular editorials appeared in AMRA's monthly newsletter.

State of Iowa Liaison Officer to the Nuclear Regulatory Commission, Des Moines IA. ('91-'94) Appointed by the Governor of Iowa as the main contract between the Nuclear Regulatory Commission and Iowa state government. Primary responsibility included keeping current on all policy issues affecting nuclear power plants – Over -

Chief, Bureau of Energy Efficiency, Auditing, and Research, Iowa Utilities Board(IUB), Des Moines IA. ('86-'92) Advised on long term energy planning, legislative, and policy matters including demand-side management, management and financial auditing, the introduction of new technology in regulated industry and rate setting for regulated electric, gas, and telephone utilities.

MIDDLE MANAGEMENT & ANALYST POSITIONS

- Supervisor of Rate Design, Rate Dept., Houston Light and Power, Houston TX ('84-'86)
- Rate Analyst, Financial Planning Dept., Arizona Electric Power, Benson AZ. ('82-'84)
- Forecasting Supervisor, Financial Planning Dept., Tri-State Generation, Denver CO ('79-'82)

EDUCATION

Ph.D., M.A. International Economics and Finance, University of Denver, 1976
M.S., Regulatory Economics, University of Wyoming, 1979

PROFESSIONAL ASSOCIATIONS

National Association of Business Economists

SPECIAL SKILLS

Distributed Processing

Personal Computers: Expert Programming in Excel Visual Basic, Power Point and all Microsoft Windows Packages.

Mathematical Modeling

Engineering Economics
Econometric Forecasting

Michael D. Chrysler
P.O. Box 20207
Nashville, Tennessee 37202
Telephone: (615)741-8726
Facsimile: (615) 532-2910
E-Mail: Michael.Chrysler@state.tn.us

Education:
Bachelor of Business Administration (Accounting)
Ft. Lauderdale University, 1970

TN AG (Consumer Advocate & Protection Division) 1998-Present

Provided analysis in Energy and Water issues, rate cases as assigned
Active in analysis related to Consumer Protection telephone issues
Testified in Docket No. 02-00383 Petition of Chattanooga Gas Company For Approval of Change in Purchased Gas Adjustment

Northern Indiana Public Service Company (NISOURCE) 1973-1997

Principal of Electric Business Planning: Electric Business Planning Department (1990-1997)
Coordinated $147 million Capital, $101 million Expense, and $789 million Margin budget development of The Electric Business, with subsequent monthly/quarterly explanation of variances reported to Senior Management.

- Provided consulting assistance to station/district planners for proper explanation of their Capital & Expense variances to Senior Management, then summarized for reporting.
- Assisted with O&M and Capital Budget ABM training (budget development and data entry in budgeting system); plus proper development of budgets for presentation and approval.
- Provided Electric Margin variance analysis by class on a monthly/quarterly basis to Senior Management.
- Developed a sophisticated computer model for the Director of Electric Production in Microsoft Excel, providing "what if" analysis along with historical data to reach a goal of $16 per megawatt hour generation cost goal.
- Assisted the Vice President and General Manager, Electric Business in the development of written speeches as well as corresponding presentation slides.

Senior Consultant: Corporate Consulting Services (1989-1990)
Responsible for providing expertise and assistance to various departments within the company, including training of management personnel on various productivity seminars and software programs.

- Researched "under-billing" of NIPSCO gas customers due to the variable of "Supercompressibility." Quantified over $200,000 of annual under-billing for the gas metering department.
- Interview NIPSCO management personnel to ensure compliance with "Automatic Time

MARK HOUGHMAN CROCKER
Resume

Mark H. Crocker
P.O. Box 20207
Nashville, Tennessee 37202
Telephone: (615) 741-8727
Facsimile: (615) 532-2910
Email: Mark.Crocker@state.tn.us

Education:

Bachelor of Arts (American History with minors in French and Economics)
Middle Tennessee State University (1975)

Master of Arts (Historic Preservation)
Middle Tennessee State University (1978)

Accounting added as Second Undergraduate Major
Middle Tennessee State University (1986)

Work Experience:

State of Tennessee, Office of the Attorney General 2001 - Present
Consumer Advocate and Protection Division
Regulatory Analyst

Review and analyze telephone tariffs as assigned
Review and analyze monthly reports submitted by utility and telephone companies
Assist other departments with accounting issues as needed

Grannis, Whisenant and Associates, Certified Public Accountants 2000-2001
Senior Manager

Prepared Corporate, Partnership, and Individual Tax Returns
Provided Audit services
Supervised office staff, bookkeepers, and staff accountant
Responsible for building client base and client relations

Wright Travel, Inc.
Chief Financial Officer 1999-2000

Wright Travel is a travel company based in Nashville, Tennessee, with 18 branch offices located in 5 states. Revenues for this company exceed $50 million annually.

- Responsible for supervising staff of 6 in the accounting department, including one accounting manager and one information systems specialist
- Responsible for preparation of sales reports for each branch on a weekly basis
- Served as liaison with bank officials, insurance company, and outside auditor
- Developed budgeting system for capital expenditures
- Supervised conversion of computer systems in all 18 branches
- Developed system of variance analysis for branch managers and CEO

Cumberland Science Museum
Vice President of Finance 1994-1999

The Cumberland Science Museum is a not-for-profit museum centered on the physical sciences located in Nashville, Tennessee. The Museum owned Grassmere Wildlife Park from 1963 to 1995.

- Reviewed and approved all purchases
- Supervised accounting staff of 2
- Supervised Vice President of Exhibits, the Vice President of Marketing and Development, the Vice President of Programs, and the Director of Human Resources
- Reported monthly operating results to the Board of Directors at monthly meetings
- Developed system of variance analysis for the Department Heads and the CEO for weekly operations meetings
- Developed budgeting procedures for operating budget and capital budget
- Worked with CEO, Chairman of the Board of Directors, Mayor of Nashville, and Metro Director of Parks to arrange purchase/transfer of Grassmere Wildlife Park to the Metro Park System
- Developed reporting system on operating results for the Sudekum family for the Sudekum Planetarium for the annual meeting
- Devised a cost accounting measurement for each student using the museum and its programs
- Developed a model for tracking restricted and non-restricted Endowment funds for Cumberland Science Museum and Grassmere Wildlife Park
- Prepared a history of the Endowment Fund
- Developed an audit response system which reduced the outside auditors' fieldwork time from six weeks to three and one-half days
- Reduced the number of audit findings from 25 in 1994 to 0 in 1999

Johnson, Jones & Crocker, Certified Public Accountants 1992-1994
Partner

Prepared Corporate, Partnership, and Individual Tax Returns
Provided Audit services
Supervised office staff
Responsible for building client base and client relations
Assisted in development of tracking system for work product

Middle Tennessee State University 1993-2002
Adjunct Professor

Served as adjunct professor in the Accounting Department
Taught Principles of Accounting I and II; Intermediate Accounting I and II; Survey of Accounting; and Management Accounting

Tennessee State University 1995-1996
Adjunct Professor

Served as adjunct professor in the Accounting Department
Taught Principles of Accounting I and II

Nashville State Technological Institute 1996
Adjunct Professor

Served as adjunct professor in the Accounting Department
Taught Auditing I

Internal Revenue Service 1987-1992
Revenue Agent

Audited corporate, partnership, and individual tax returns
Served as On the Job Instructor for Phase One revenue agents
Served as classroom instructor for revenue agents for Phase One Training
Served on national task force to audit Low-Income Housing Bonds; the only agent in the Nashville District selected for this responsibility
Served on national task force to write audit procedures for auditing tax-exempt bonds

State of Tennessee, Comptroller's Office, Division of Municipal Audit 1986-1987
Legislative Auditor

Reviewed audits of municipalities, school districts, and public utilities in northwest Tennessee
Participated in audits of municipalities, school districts, and public utilities in Tennessee
Instrumental in discovering a case of fraud in a utility district
Requested to serve on special investigative team in a school district audit in which fraud was suspected

Honors and Awards:

Received Certified Public Accountant license in 1992
Member of the American Institute of Certified Public Accountants
Member of the Tennessee Society of Certified Public Accountants
Member, Gamma Beta Phi Honor Society
Member, Alpha Beta Psi Honor Society

1606 Shackleford Road
Nashville, TN 37215-3522

615 279-9108
dmccormac@comcast.net

Daniel W. McCormac

Experience

<u>2001 to 2003</u> Tennessee Regulatory Authority - Chief of Energy and Water Division
Responsible for review of all tariff filings, review of rate adjustment filings, audits, and responses to inquiries and complaints on all accounting, tariff and ratemaking matters in the gas, electric, water and wastewater industries. Advised Commissioners on all material and contested matters.

<u>1994 to 2001</u> Tennessee Attorney General's Office, Consumer Advocate & Protection Division - Senior Regulatory Analyst
Provided management analysis and expert testimony as needed in major rate cases, earnings reviews, tariff filings, rule changes, and other investigations.

<u>1987 to 1994</u> Tennessee Public Service Commission (TPSC) - Manager of Revenue Requirements and Special Studies
Supervised seven professionals, coordinated rate cases, earnings reviews, and other financial investigations of telephone, gas, electric, water, and sewer utilities. Testified on major issues.

<u>1984 to 1987</u> Wilson, Work, Fossett & Greer, CPAs - Supervisor
Consulted and assisted public utilities in preparing rate cases, cost of capital studies, cost of service studies, Purchased Gas Adjustment rule proposal, capital structure study, valuation study, computer software, research.

<u>1983 to 1984</u> TPSC - Technical Assistant to Commissioners
Chosen as first Technical Assistant to review and summarize all rate case filings, provide commissioners with research reports, prepare issues lists and analyze those issues. Also assisted in administrative accounting and budgeting by computerizing office records.

<u>1976 to 1983</u> TPSC - Financial Analyst / Supervisor
Audited and analyzed rate case filings, testified and prepared exhibits for the TPSC.

<u>1972 to 1976</u> Various - Steam plant operator, bookkeeper, store clerk

Goals

Serve the citizens of Tennessee, employees of the Attorney General's Office, and the TRA and its staff in a fair and equitable manner.

Strive to establish and maintain utility rates and service policies that are fair and reasonable to both consumers and providers.

Education & Certification

1973 – 1976	David Lipscomb University, B.S., Accounting
March 1979	Certified Public Accountant
1981	TSU, Business Finance, Business Management

Discovery Request Response 6

The Role of Double Leverage in Determining the Cost of Capital for a Regulated Subsidiary of a Holding Company

Prepared for the NARUC Ad Hoc Committee on Diversification

by

David S. Habr
Utilities Division - Iowa Department of Commerce*

February 24, 1987

* The views expressed herein do not necessarily reflect the views of the Utilities Division or the Iowa Public Utilities Board.

The Role of Double Leverage in Determining the Cost of Capital for a Regulated Subsidiary of a Holding Company

Introduction

The cost of capital has become the general basis for determining the fair rate of return a utility is given the opportunity to earn. Use of the cost of capital allows the utility to recover the cost of senior securities and common equity used to support assets devoted to utility operations. For the "typical" utility, the cost of capital reflects the sum of the weighted embedded costs of senior securities (generally mortgage bonds, debentures, preferred stock, preference stock) and the "current"[1] weighted cost of common equity. Within this framework, the determination of the market based cost of common equity is the most controversial item.

With the formation of a holding company with the utility operating company as a subsidiary, the cost of capital determination may become cumbersome. It is no longer possible to use market data for the stock of the utility company to determine the utility's cost of common equity; the utility company's common stock is now owned by its parent. In fact, the utility's entire common equity account reflects amounts the parent company has contributed either by direct purchase of common stock or through the decision to leave earnings in the utility company or both.

In the following discussion it is shown that double leverage is a valid method to use to determine the cost of the subsidiary's common equity[2]

---

1. The definition of current varies between jurisdictions. However, these different definitions do not have an impact on the following double leverage analysis.

2. Double leverage can either be thought of as a method for determining a subsidiary's cost of common equity or as a method for identifying the actual capital structure (and associated costs) used to support the investment in utility operating assets.

and that this method is consistent with the capital attraction standard. The next two sections describe the mechanics of double leverage. In the first section, the flows and costs of external funds in the holding company relationship are described. The second section describes how the equity and cost methods of accounting for retained earnings affect the double leverage calculation. Section three explains why double leverage is consistent with cost based ratemaking while section four examines additional topics related to holding companies and double leverage.

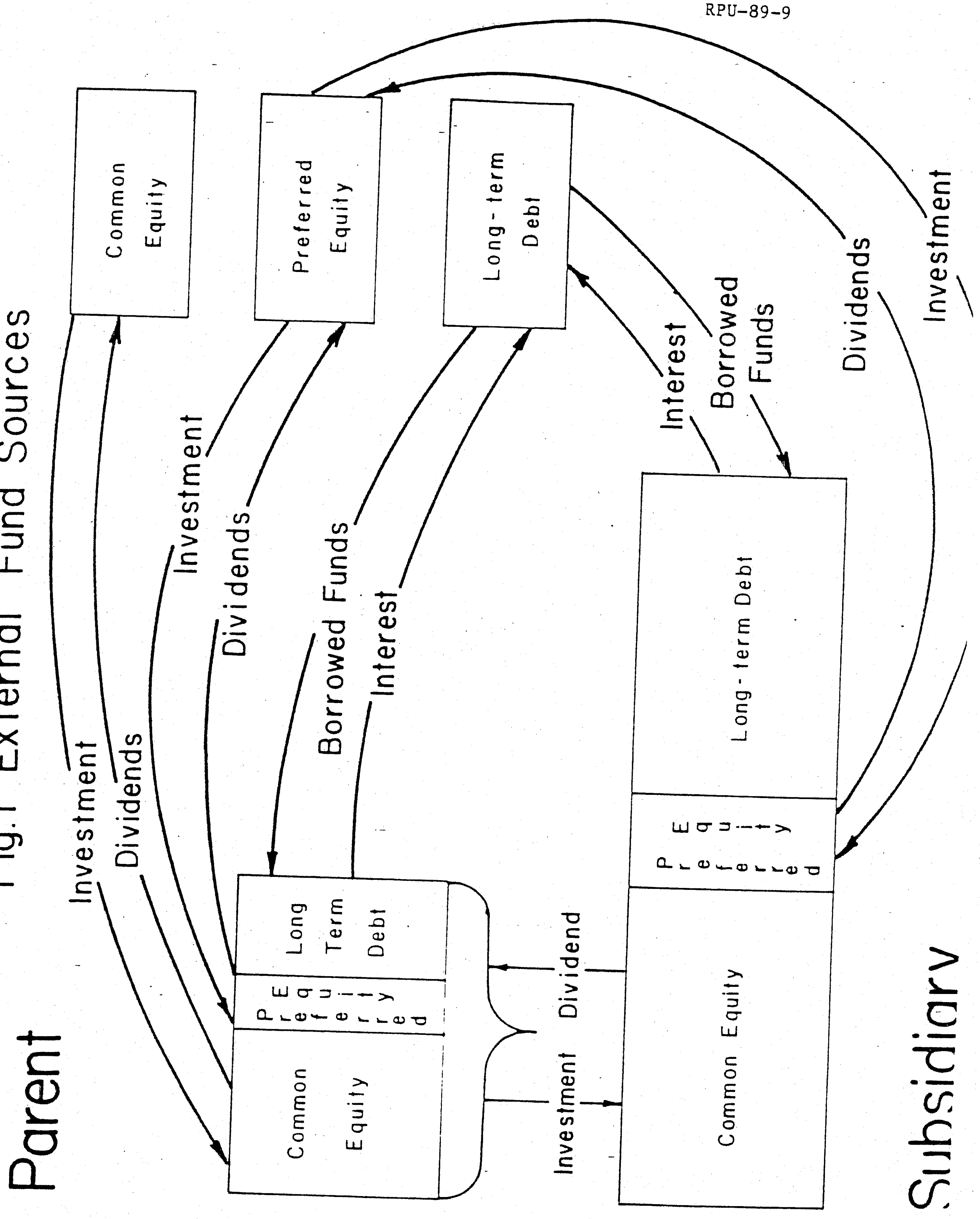
External Sources and Costs of Funds

The potential external sources of permanent funds for use to support rate base are shown in Figure 1. To keep the basic flows and principles in the spotlight, a simple holding company relationship of a parent with a single, 100 percent owned subsidiary has been adopted.

Both preferred (or preference) equity and long-term debt are obtained in the open market by the parent and the subsidiary. The parent's common stock is traded in the open market and the parent can obtain new common equity by issuing new common shares and selling them in the open market or by retaining a portion of current earnings.

However, the subsidiary is not able to sell its common shares on the open market. Its only source of new common equity is to obtain such from its parent. This new equity can be obtained by the parent company's purchase of new issues of the subsidiary's common stock or, as is more often the case, by the parent company electing to have the subsidiary pay-out less than 100 percent of its earnings as dividends. The latter method avoids all the "hassles" associated with a 100 percent earnings payout and

Fig. I External Fund Sources



the possible subsequent need to issue additional subsidiary common stock to obtain additional funds from the parent.

The cost of common equity for the parent company and the costs of preferred equity and long-term debt for both the parent and the subsidiary can be determined from information directly generated in the capital market.[3] That is, the minimum amount that has to be paid to attract capital can be determined directly from market information for the subsidary's preferred equity and long-term debt and all of the parent's capitalization.

Given that all of the costs of the parent's capitalization are known, it is a simple process to determine the cost of the funds the parent uses to invest in the common equity of its subsidiary. The cost of these funds is simply the parent's weighted average cost of capital.[4] Use of the parent's weighted average cost reflects the fungible nature of money; i.e., there is no way to tell where a dollar came from once it is thrown into a "pot." But, the dollars, as a group, must come out in the same proportions they went in.

Mechanics of Double Leverage

In a holding company relationship there are two different ways the parent company can account for the retained earnings of its subsidiaries on its balance sheet, the equity method and the cost method. The equity

---

3. The current cost of new issue of preferred stock and long-term debt become the embedded costs of these issues as time passes.

4. This statement assumes that the equity method of accounting for retained earnings has been used. The difference between the equity and cost methods of accounting for retained earnings is described in the next section.

method was implicitly used in the preceding section. With this method, the retained earnings of the subsidiary are carried on both the parent's and the subsidiary's balance sheet.[5] The total common equity reported on the parent's balance sheet under this method is the same as that shown on the consolidated balance sheet.

The equity method breakdown is illustrated in Figure 2. Note that in this case the total common equity of the subsidiary is equal to the total capitalization of the parent. In general, the total common equity of all the subsidiaries (for a holding company with more than one subsidiary) will equal the total capitalization of the parent.

Calculating the cost of capital for the subsidiary is fairly straight forward. The example in Table 1 continues the assumption of a holding company with a single subsidiary. It is also assumed (for sake of simplicity) that the parent's only asset is its investment in its subsidiary. Thus, the parent's entire capitalization is invested in the common equity of its subsidiary.

The overall return at the subsidiary level is 10.787 percent. This overall return reflects the subsidiary's embedded costs of long-term debt and preferred equity and a subsidiary common equity cost equal to the parent's weighted average cost of capital. Not only will this return cover the subsidiary's embedded costs of senior securities, it will generate a return <u>available</u> to the parent sufficient to cover the parent's embedded costs of senior securities plus the 12 percent expected return on the common equity in the parent's common equity account.

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5. Note that the parent's balance sheet is simply that; the balance sheet of the parent company only. The parent's balance sheet is not the same thing as the consolidated balance sheet.

Fig. 2 Equity Method of Accounting for Retained Earnings

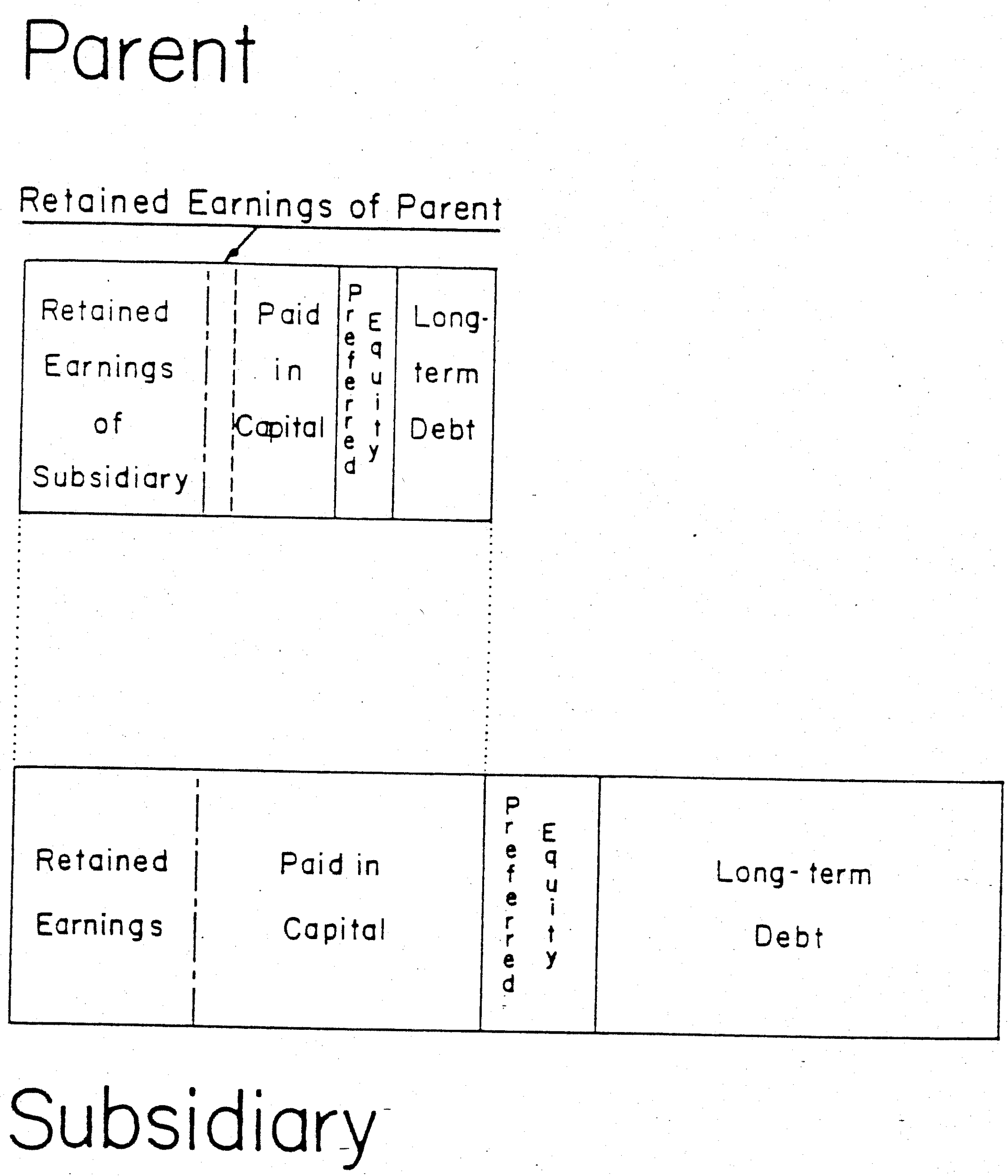

Table 1. Weighted Cost of Capital When Equity Method of Accounting for Retained Earnings is Used

Parent Capitalization and
Weighted Cost of Capital

		Ratio	Cost Rate	Weighted Cost
Long-term Debt	$20,000	20.0%	11.0%	2.200%
Preferred Equity	5,000	5.0	9.5	0.475
Common Equity				
Paid in Capital	45,000	45.0	12.0	5.400
Parent's RE	5,000	5.0	12.0	.600
Subsidiary RE	25,000	25.0	12.0	3.000
	75,000	75.0		9.000
Total	$100,000	100.0%		11.675%

Subsidiary Capitalization and
Weighted Cost of Capital

		Ratio	Cost Rate	Weighted Cost
Long-term Debt	$ 90,000	45.0%	10.0 %	4.500%
Preferred Equity	10,000	5.0	9.0	0.450
Common Equity				
Paid in Capital	75,000	37.5	11.675	4.378
Retained Earnings	25,000	12.5	11.675	1.459
	100,000	50.0		5.837
Total	$200,000	100.0%		10.787%

Under the cost method the subsidiary's retained earnings do not appear on the parent's balance sheet.[6] This method is depicted in Figure 3. Under this method, the parent is treated as if it can only invest in its subsidiary by contributing to the subsidiary's paid in capital.

Table 2 provides an illustration of the proper method for determining the subsidiary's cost of common equity and overall return when the cost method is used to account for subsidiary retained earnings. This illustration maintains the assumption that the parent's only asset is its investment in its subsidiary.

The important point to note in this case is that the parent's cost of common equity is applied to the subsidiary's retained earnings while the parent's weighted cost of capital is applied to the subsidiary's paid in capital. Again, the overall rate of return at the subsidiary level is 10.787 percent which is sufficient to cover all of the embedded costs of senior securities (parent and subsidiary) and provide the expected 12 percent return on parent's common equity plus the subsidiary's retained earnings.

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6. On the asset side of the parent's balance sheet, its investment in the subsidiary is recorded at cost rather than at equity (as is the case under the equity method).

Fig. 3 Cost Method of Accounting for Retained Earnings

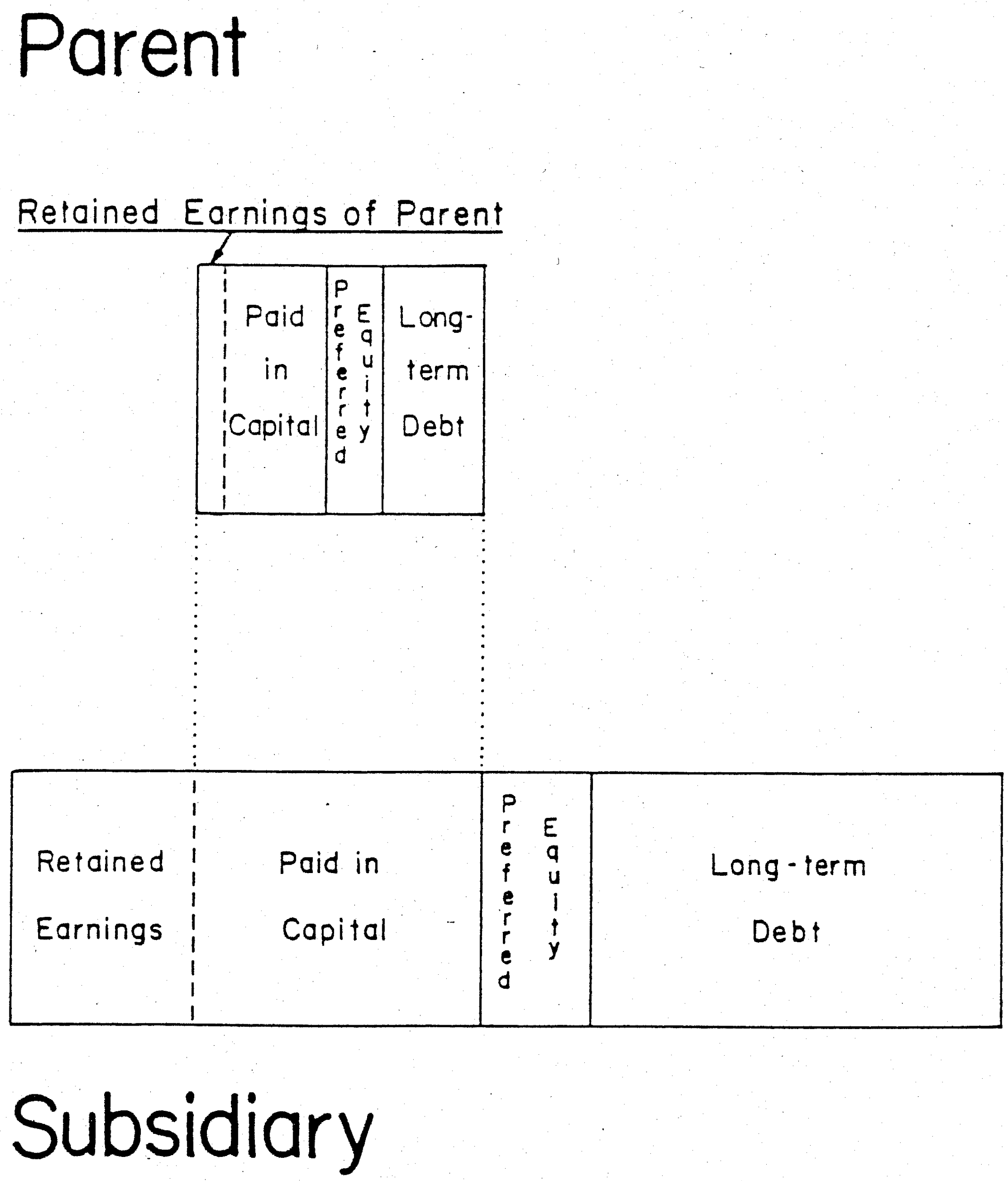

Table 2. Weighted Cost of Capital When Cost Method of Accounting for Retained Earnings is Used

Parent Capitalization and Weighted Cost of Capital

		Ratio	Cost Rate	Weighted Cost
Long-term Debt	$20,000	26.667%	11.0%	2.933%
Preferred Equity	5,000	6.667	9.5	.633
Common Equity				
Paid in Capital	45,000	60.000	12.0	7.200
Parent's RE	5,000	6.667	12.0	.800
	55,000	66.667		8.000
Total	$75,000	100.000%		11.566%

Subsidiary Capitalization and Weighted Cost of Capital

		Ratio	Cost Rate	Weighted Cost
Long-term Debt	$ 90,000	45.0%	10.0 %	4.500%
Preferred Equity	10,000	5.0	9.0	0.450
Common Equity				
Paid in Capital	75,000	37.5	11.566	4.337
Retained Earnings	25,000	12.5	12.000	1.500
	100,000	50.0		5.837
Total	$200,000	100.0%		10.787%

Another way to combine the effects of leverage at the parent and the subsidiary level to determine the cost of capital for the subsidiary operations is to use the consolidated capital structure. This capital structure reflects the net amounts of the total capitalization for both the parent and the subsidiary. For the simple, single subsidiary holding company that has been used thus far, the consolidated capital structure makes explicit the implicit segmentation of the subsidiary's common equity account that takes place with both the cost and equity methods of double leverage.

As is shown in Figure 4, consolidation, in effect, substitutes the parent's capitalization for the subsidiary's paid in capital. The resulting capitalization reflects the actual capitalization used to support the subsidiary's utility assets. In this case the parent's market cost of common equity is applied to the entire common equity account.

The consolidated cost of capital (again using the numerical values from the previous examples) is shown in Table 3. As before, the overall return is 10.787 percent. In this case, the consolidated capital structure makes clear the actual capitalization used to support the utility operations. However, this clarity is only valid for a holding company with a single subsidiary or multi-subsidiary holding company all of whose subsidiaries have the same capitalization ratios.

Double Leverage and Cost Based Rate Making

From the examples in the preceding section, it would seem that either double leverage method or the consolidated capitalization and cost rates could be used (with indifference) to determine the cost of capital for the

Fig.4 Construction of Consolidated Capital Structure

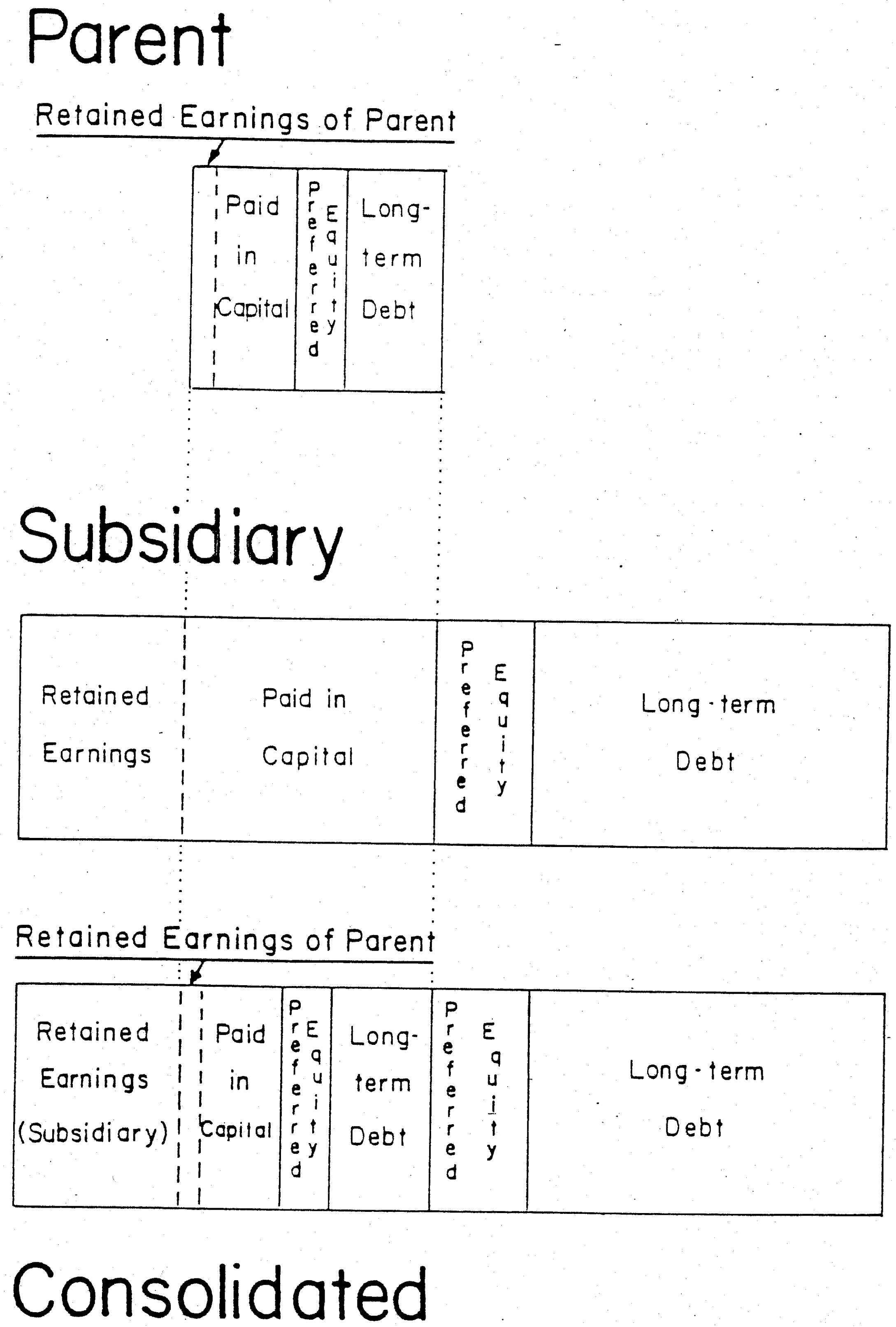

Table 3. Consolidated Weighted Cost of Capital

		Ratio	Cost Rate	Weighted Cost
Long-term Debt				
Parent	$ 20,000	10.0%	11.0%	1.100%
Subsidiary	90,000	45.0	10.0	4.500
	110,000	55.0		5.600
Preferred Equity				
Parent	5,000	2.5	9.5	.237
Subsidiary	10,000	5.0	9.0	.450
	15,000	7.5		.687
Common Equity				
Parent Paid in Capital	45,000	22.5	12.0	2.700
Parent RE	5,000	2.5	12.0	.300
Subsidiary RE	25,000	12.5	12.0	1.500
	75,000	37.5		4.500
Total	$200,000	100.00%		10.787%

operating subsidiary. Unfortunately, this is only true for a holding company with a single subsidiary. Once there is more than one subsidiary in the holding company, it is not an automatic truism that the consolidated capitalization and cost rates reflect accurately the cost of the capital used to support the rate base of one of the operating subsidiaries.

For example, use of the consolidated capitalization and cost rates assumes that each subsidiary has the same capital structure ratios and the same embedded costs of senior securities. Use of the consolidated method requires subsidiaries with lower embedded costs of senior securities to subsidize subsidiaries with higher embedded costs of senior securities.

On the other hand, either the equity or the cost method provide proper estimates of the cost of the effective capitalization used to support a specific subsidiary's utility operations. Because each of these methods reflects all capital costs, including the market cost of common equity, each double leverage method meets the capital attraction criteria.[7] That is, each of these methods generates a subsidiary rate of return that is sufficient to give the subsidiary the opportunity to recover the embedded costs of all senior securities used to support its rate base and cover the return investors expect to earn on their investment in the common equity of the subsidiary's parent.

Companies, however, quite often argue that the subsidiary should be given the opportunity to earn a "full" return on all of the subsidiary's common equity. Acceptance of this argument means that the parent company

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7. See, for example, Jules Blackman and Jack B. Kirsten, "Double Leverage and the Cost of Equity Capital," Public Utilities Fortnightly, 90 (September 28, 1972):32-37.

is treated as if it is 100 percent common equity financed. As long as the embedded costs of senior securities are less than the market cost of common equity (as has generally been the case), the difference between the common equity return and the embedded costs of senior securities will accrue to the common shareholders as a return in excess of that which is needed to compensate them for the risks they assumed. For example, if the subsidiary in the preceding examples is allowed to earn 12 percent on its common equity, the parent company (and its common stockholders) will earn 12.43 percent on the common equity it used to support its investment in its subsidiary.

Of course, the opposite is true if the current cost of common equity falls below the embedded costs of senior securities. If the parent's cost of common equity falls to 10.5 percent and the subsidiary is allowed to earn this on its common equity, the parent company will earn only 10.43 percent on its common equity it has invested in its subsidiary.

Double leverage calculations based on the equity method are probably the most common because the common equity account of the parent under this method is the same as that reported on the consolidated balance sheet. A typical "company" attack on this method is that the subsidiary's retained earnings are not available to the parent for investment in other operations and therefore should be granted a "full" (i.e., parent's market cost of common equity) common equity return. It was shown in the previous section that this argument is a veil.[8] However, the cost method provides a simple means to defuse this argument.

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8. Recall that the subsidiary's retained earnings earn a "full return" at the parent level.

Additional Topics Related to Double Leverage

All of the previous discussion has been based on a pure utility holding company, i.e., the parent's assets are the subsidiary stock it owns and each subsidiary is a pure utility. The chances of actually finding such a creature are slim. Rather, most holding companies have some subsidiaries that are not utility operations. For example, one of the subsidiaries of Midwest Energy (an Iowa holding company) owns unit trains while American Water Works Service Company basically operates as a "consulting" firm for the operating subsidiaries of American Water Works. The Bell regional holding companies have and continue to form subsidiaries which are involved in non-regulated activities (or activities which they believe should be non-regulated).

Obviously, the market cost of common equity for the parent holding company reflects all of the activities of the various subsidiaries. It is not unreasonable to assume that the market cost of common equity for the parent is a weighted average of the market cost of common equity related to each of the activities of the various subsidiaries. The question is how to decompose this weighted average.

Michael Rozeff has developed one method for dealing with this problem.[9] The parent weighted cost of capital to be applied to the utility subsidiary's common equity is found by treating the parent's unadjusted weighted cost of capital as the weighed average of the return required on its investment in the common equity of each of its subsidiaries. Assuming

9. Michael S. Rozeff, "Modified Double Leverage--A New Approach," Public Utilities Fortnightly, 111(March 31, 1983):31-36.

that the required return on the investment in the common equity of the unregulated subsidiary is known, it is a simple process to "back" into the expected return on the common equity of the utility operations.

On the other side, William Beedles has proposed that capital structures be adjusted rather than estimating the cost of common equity for the non-regulated subsidiary.[10] Both types of adjustments have been made in Iowa but the adjustments were not based on either of the articles mentioned. In fact, the adjustments had been made prior to the publication of either article.

A more completed discussion of these and other proposals is beyond the scope of this paper. However, there is one important point that must be made. Neither of the above articles or others in the same vein, have anything to do with double leverage as such (even though the term appears in the title). Double leverage is simply a process by which a subsidiary's cost of capital can be estimated given the parent's cost of capital. Both of the above articles are concerned with changing the existing costs or capital structures that are inputs in the double leverage process.

Much of the confusion about double leverage can be avoided if double leverage is looked at as a method to determine the actual capitalization used to support utility operations instead of a method to be used to determine the cost of common equity for a subsidiary. The former is in fact what double leverage does. Indicating that the parent's weighted cost of capital is the subsidiary's cost of common equity is simply taking a "snap shot" of one point in one method for recognizing double leverage.

10. William S. Beedles, "A Proposal for the Treatment of Double Leverage," Public Utilities Fortnightly, 114(July 5, 1984):31-36.

As is shown in Tables 4 and 5, it is entirely possible to determine the weighted cost of capital used to support the subsidiary's utility operations without explicitly calculating the cost of the subsidiary's common equity. With this double leverage method, the subsidiary's common equity is decomposed into the portions that reflect the sources of funds used by the parent to support its investment in the subsidiary's common equity. Hence, after the decomposition the subsidiary has no common equity.

Table 4. Parent and Subsidiary Capitalization and Cost Rates*

Parent Capitalization and Cost Rates

		Ratio	Cost Rate
Long-Term Debt	$ 20,000	20.0%	11.0%
Preferred Equity	5,000	5.0	9.5
Common Equity	75,000	75.0	12.0
Total	$100,000	100.0%	

Subsidiary Capitalization and Cost Rates

		Ratio	Cost Rate
Long-Term Debt	$ 90,000	45.0%	10.0%
Preferred Equity	10,000	5.0	9.0
Common Equity	100,000	50.0	---
Total	$200,000	100.0%	

*Equity method used to account for retained earnings.

Table 5. Allocation of Subsidiary Common Equity and Weighted Cost of Capital

	Parent Ratio	Subsidiary Common Equity Ratio	Proportion of Subsidary Capitalization Supported by Parent	Proportion of Subsidary Common Equity Supported by Parent	Amount of Subsidiary Common Supported by Parent
Long-Term Debt	20.0%	50.0%	10.0%	20.0%	$ 20,000
Preferred Equity	5.0	50.0	2.5	5.0	5,000
Common Equity	75.0	50.0	37.5	75.0	75,000
Total	100.0%		50.0%		$100,000

	Amount	Ratio	Cost Rate	Weighted Cost
Long-Term Debt				
Subsidiary	$ 90,000	45.0%	10.0%	4.500%
Parent	20,000	10.0	11.0	1.100
	110,000	55.0		5.600
Preferred Equity				
Subsidiary	10,000	5.0	9.0	.450
Parent	5,000	2.5	9.5	.237
	15,000	7.5		.687
Common Equity				
Subsidiary	N.A.	N.A.	N.A.	N.A.
Parent	75,000	37.5	12.0	4.500
	75,000	37.5		4.500
Total	$200,000	100.0%		10.787%

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Double Leverage One More Time

By BASIL L. COPELAND, JR.

In the oft-cited case of Federal Power Commission v Hope Nat. Gas Co. (1944) 320 US 591, 51 PUR NS 193, 88 L Ed 333, 64 S Ct 281, the U. S. Supreme Court stated (at 603) that:

> The investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard 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 to attract capital.

This opinion did not endorse any particular method for determining the appropriate rate of return. But regulatory practice and tradition recognize the usefulness of the cost-of-capital approach to rate of return regulation because a rate of return so determined is consistent with the standards set out in the Hope decision. A firm that is allowed to earn its cost of capital will be able to service the fixed capital costs of its senior capital and earn a return on equity that properly compensates the shareholders for the risk they bear and the consumption opportunities they forego.

The author offers what he believes is a definitive response to all arguments — many of which have been stated in past issues of this magazine — against the concept of "double leverage," or, in other words, the definitive argument in favor of its recognition in regulatory determinations of the cost of capital and a fair rate of return for subsidiaries of utility holding companies. The position taken in this article is the author's and should not be interpreted as the opinion or policy of the Iowa State Commerce Commission.

Basil L. Copeland, Jr., is a staff economist with the Iowa State Commerce Commission. Prior to joining the ISCC staff, he had a similar position with the Arkansas Public Service Commission. In addition to testifying on the subject of rate of return, he has presented conference papers on the subject of the cost of capital before the Southwestern Finance Association and the Mid-America Regulatory Commissioners' conference. **Mr. Copeland** received a BS degree in economics and an MS degree in resource economics from Oregon State University.

There is a certain amount of disagreement, and a considerable amount of misunderstanding, about how properly to apply the cost-of-capital concept to the subsidiary of a holding company that employs leverage to purchase the equity of the subsidiary. When determining the cost of capital for the subsidiary of a holding company, is it proper to recognize and give effect to the "double leverage" that exists if the holding company has employed leverage to purchase the equity of the subsidiary? The question is guaranteed to provoke a negative response from utilities that employ this form of corporate arrangement. We should not be too surprised at the vigor of their opposition since they have a definite pecuniary interest in preserving the comparative advantage this form of corporate arrangement has over ordinary corporate arrangements: Presuming that regulatory authorities ignore the effect of double leverage in determining the rate of return to be allowed the subsidiaries of utility holding companies, the holding companies can, have, and will no doubt continue to earn millions of dollars of income in excess of their cost of capital. Their opposition to regulatory recognition of the effect of double leverage should therefore be taken for what it is worth.

In regulatory proceedings where double leverage is an issue the utility under review generally tries to avoid any appearance that might suggest that its position is based merely upon self-interest. The company may attempt to accomplish this end in any of several ways. It may, for example, lay great stress upon the fact that the case for regulatory recognition of the effect of double leverage has been explicitly rejected in some jurisdictions.[1] But the citing of precedent, though a time-honored legal tradition, may only serve to preserve the mistakes of the past. Each commission should always strive to avoid the ignominy of signifying its approval of opinions that were ill advised. This implies a need for each commission to judge the case on its merit rather than rely upon what other commissions have done. To lend a further aura of objectivity to its position the company may also adduce support by referencing published articles that support its position.[2] But anyone can cite a reference containing conclusions that happen to support one's prejudices. The task incumbent upon anyone interested in the truth of a matter is to examine whether the arguments leading up to the conclusions are of any merit. As it turns out, the case against regulatory recognition of double leverage is a finely spun web of fallacy, half-truth, and misunderstanding. Its silken threads hang together with just enough plausibility to invite belief by the unsuspecting and by those who have prior cause to believe that a case against double leverage exists. But the web will not support the weight of careful and objective analysis.

Double leverage is an issue that refuses to die precisely because a consistent application of the cost-of-capital standard demands that the effect of double leverage be given adequate consideration when determining the cost of capital for the subsidiary of a holding company. The case for double leverage is so simple, and yet so compelling, that it cannot be suppressed by the fact that a few commissions have erred in rejecting it or because certain articles claiming to have refuted the concept have been published. Still, some credibility, however unjustified, continues to be given the case against double leverage. Further education is obviously needed. The purpose of this article is to restate the case for regulatory recognition of the effect of double leverage within the context of the traditional rationale for public utility regulation. Arguments often advanced against the double leverage concept will be considered and refuted on a point-by-point basis.

The Logical Basis for Giving Effect To Double Leverage

The cost-of-capital approach to utility regulation can be rationalized within the context of the modern theory of capital budgeting.[3] This theory has been articulated in both normative and positive versions. The normative version of the theory sets forth certain decision rules that a firm should follow if its objective is to maximize the value of the firm. For example, the theory suggests that in order to maximize the value of the firm, the firm should undertake all investment projects that have an internal rate of return greater than the firm's cost of capital. Alternatively, the theory suggests that the firm should undertake all investment projects that have a positive net present value when the costs and benefits of the project over time have been discounted at a rate equal to the firm's cost of capital. The positive version of the theory presumes that firms make investment decisions so as to maximize the value of the firm. Assuming they do, competition and the goal of profit maximization will induce firms to increase investment as long as the internal rate of return on investment is greater than the cost of capital. Competitive equilibrium is reached when the internal rate of return on the last investment project undertaken just equals the cost of capital. In competitive equilibrium the net present value of the last investment project undertaken is zero.

The accepted rationale for utility regulation is to emulate the competitive result in a business environment that by nature invites monopoly. In competitive equilibrium the marginal return on investment just equals the cost of capital and the net present value of the marginal investment is zero. This provides the rationale for restricting the return on utility investment to the utility's cost of capital. If this result is accomplished then the net present value of investment in utility plant is zero; the internal rate of return over time will be just equal to and offset by the utility's cost of capital.

When these same principles are applied to the case of a utility holding company they lead to the conclusion that the holding company should be constrained to a return on its investments in utility subsidiaries equal to its weighted average cost of capital since the holding company's average cost of capital reflects the degree of financial leverage inherent in its capital structure this approach automatically gives effect to the double leverage that exists when a holding company employs leverage to purchase the equity of a subsidiary. (In prac-

[1] See, for example, Re Michigan Bell Teleph. Co. (1970) 85 PUR3d 407, and (1974) 3 PUR4th 1; and Re Southeastern Teleph. Co. (1973) 98 PUR3d 369.

[2] Reference is in particular to, "What Are the Real Double Leverage Problems?," by Eugene M. Lerner, 91 Public Utilities Fortnightly 18, June 7, 1973; "Double Leverage Indisputable Fact or Precarious Theory?," by James E. Brown, 93 Public Utilities Fortnightly 26, May 9, 1974; and, "Subsidiaries' Capital Costs — A Compromise Approach," by Dennis B. Fitzpatrick, 99 Public Utilities Fortnightly 23, June 23, 1977.

[3] For a discussion of capital budgeting concepts see almost any undergraduate text in financial management, e.g., "Managerial Finance," by Weston and Brigham, The Dryden Press, Hinsdale, Illinois.

tice the double leverage concept may be implemented either by using the subsidiary's capital structure and restricting the return on equity to the parent's cost of capital, or by basing the allowed rate of return on the consolidated cost of capital and capital structure. The latter practice has been traditionally applied in cases involving Bell system subsidiaries and consequently double leverage has never been the issue for the Bell system that it is for independent telephone holding company systems.)

Furthermore, these same principles suggest that the competitive norm which regulation strives to emulate is violated when a utility holding company is allowed to earn returns on its investments in subsidiaries in excess of its cost of capital.

This is the case for double leverage. It is simple and compelling. But it has not gone unchallenged. The next section considers the arguments that are often advanced in opposition to regulatory recognition of the effect of double leverage.

The "Case" against Double Leverage

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The articles by Brown and Lerner, previously noted (footnote 2), are the sources cited most often by those who oppose regulatory recognition of the effect of double leverage. The following arguments, considered on a point-by-point basis, seem to represent the substance of their "case" against double leverage.

Argument One — It is argued that application of the double leverage concept discriminates against the holding company arrangement. There are some variations on this theme that are considered below as separate arguments. Now if by "discrimination" is meant "differently" then it probably cannot be denied that the double leverage concept treats the subsidiaries of holding companies differently than firms that are not subsidiaries. But so what? Is it not obvious that subsidiaries of holding companies *are*, by virtue of that very fact, *different* than firms that are not subsidiaries. Since they are different, commissions must be careful to determine whether or not the difference has implications for regulatory practice and methodology. On the other hand, if by "discrimination" the opponents of double leverage mean to imply that the double leverage concept precludes them from earning a fair rate of return, then the argument is completely and utterly without merit.

The double leverage concept constrains the subsidiary of a holding company to the *same* standard of fair return that applies to all regulated utilities; i.e., that the net present value of investment in utility plant be zero. If there is any sort of "discrimination" to be concerned about it is the discrimination that exists in jurisdictions that ignore double leverage and allow holding companies through their subsidiaries to earn a positive net present value on utility investment. The Iowa State Commerce Commission correctly pointed out this fact in an order involving a subsidiary of Continental Telephone Corporation. It said:

> If we were to ignore this double leverage and allow the subsidiary a return on its "apparent" equity investment in utility plant equal to the market cost of equity, this could result in the parent's shareholders earning more on their investment in the company than the market cost of equity. Permitting this to occur not only results in greater earnings to the actual equity holder than is proper, but also *discriminates against those companies who do not engage in double leveraging, and whose shareholders are restricted to earnings on their investments in the company equal to the market cost of equity.* (Emphasis supplied.)[4]

The argument that double leverage discriminates against holding companies is specious and deserves to be ignored.

Argument Two — Another common argument, related to the one above, is that application of the double leverage concept is unreasonable because it would result in two firms identical in every other respect having materially different allowed rates of return simply because one was the subsidiary of a holding company and the other was not. This is a "straw man" argument because there are probably no two companies identical in every respect except that one is the subsidiary of a holding company whereas the other is not. But for the sake of argument we will assume that there are. It still does not follow that application of the double leverage concept leads to materially different allowed rates of return for the two companies or even that the subsidiary will be constrained to a lower rate of return than the other. The argument ignores the fact that there exists a difference in the financial risk to which the capital invested in these two companies is exposed and that this difference, when given effect to in the overall rate of return, will tend to equalize the returns allowed and may even result in the subsidiary being allowed a *higher* return.

A typical equity ratio for a consolidated independent telephone holding company is about 33 per cent.[5] If some of the consolidated leverage is at the parent level, then the equity ratio of the average operating subsidiary is necessarily greater than the consolidated equity ratio. For the sake of argument assume that a consolidated telephone holding company's capital structure is 33 per cent equity and 67 per cent debt while the capital structure of an average operating subsidiary of the company is 45 per cent equity and 55 per cent debt. The substance of the argument being made by those who oppose regulatory recognition of the effect of double leverage is that application of the double leverage concept to the subsidiary of the holding company would result in a lower rate of return than would be allowed another

[4] In Re Hawkeye State Teleph. Co. (1974) 2 PUR4th 166, 180, 181.

[5] According to figures published by C. A. Turner & Associates, the four largest independent telephone holding company systems have the following consolidated equity ratios: Central Telephone and Utilities Corporation, 35 per cent; Continental Telephone Corporation, 34 per cent; General Telephone and Electronics Corporation, 32 per cent; and United Telecommunications, Inc., 34 per cent.

now 50 per cent equity and 50 per cent debt. All of the parent company's capital is invested in the subsidiary and for *accounting* purposes is shown as equity on the subsidiary's balance sheet. For accounting purposes the subsidiary now shows capitalization of $67 of equity and $33 of debt which is the exact *opposite* of that which existed prior to the reorganization. Since the market cost of equity is 12 per cent and the market cost of debt is 9 per cent the company is now asking to earn $11 a year. But what happened to alter the categories of existence that originally gave metaphysical concreteness to the conclusion that $10 was a fair return? *Absolutely nothing*! By the gimmick of a corporate reorganization the utility has created accounting categories of existence which no longer correspond to the economic categories of existence that give concreteness to the economic concepts of capital and the cost of capital. Since the concept of risk and return is an economic concept, and not an accounting concept, the capital structure used to calculate the cost of capital should reflect economic categories of existence rather than accounting categories of existence. When a company creates accounting categories of existence that do not correspond to the requisite economic categories of existence, it is necessary to adjust the capital structure. Double leverage does this.

The argument that the form of ownership of equity has nothing to do with the required return on equity is correct *if* we are talking about equity as an economic concept or category of existence. But from a purely metaphysical standpoint the categories of existence that are meaningful to the accountant may be meaningless to the economist. The opponents of regulatory recognition of double leverage are engaging in metaphysical double-talk when they argue that accounting equity should necessarily be allowed the same return as economic equity.

Argument Four — The argument we now come to consider is considered by Brown to be the argumentum reductio ad absurdum of the case against double leverage; i.e., the argument that presumes to demonstrate the absurdity of double leverage concept by carrying it to its "logical" extreme. It is argued that if "double leverage is to be a valid concept it must be carried to its ultimate conclusion or lose its validity by stopping the argument in midstream." According to this argument, the double leverage concept, to be consistent, must be applied to the individual investors who purchase the parent company's common stock. Then the question is asked: "Where did the stockholders of the parent company obtain their funds?" It is suggested that if individual investors employ personal leverage then a logical extension of the double leverage concept implies "triple" leverage. But if there are millions of stockholders, so the argument goes, each with his or her own personal leverage rate, then application of the concept to the problem of "triple" leverge becomes a practical impossibility. Presuming, then, that a logical extension of double leverage requires application of a "triple" leverage concept to the use of personal leverage by millions of individual investors, Brown asks: "How would the regulatory process take this absurdity into consideration? Or does the concept of double leverage somehow conveniently stop with one subsidiary and its immediate parent? If so, why?" Since Brown seems earnest in wanting someone to help him understand why the double leverage concept does not have to be carried to the "logical" extreme of applying it to the use of personal leverage by individual investors, let us do just that.

Assume that investors have some rate of return that they require to earn on personal funds (as opposed to borrowed funds) in order to compensate them for abstention and uncertainty; and assume also that they have access to a source of borrowed funds that enables them to employ personal leverage. Further suppose, at least initially, that by employing this leverage to commingle personal funds with borrowed funds individual investors find that they are able to invest in the common stock of a holding company and earn *more* on their personal funds than the amount they require, after paying the interest cost of the borrowed funds. This, basically, is the situation envisioned by Brown. He wants to know why the double leverage concept should not be applied to individual investors in order to prevent them from employing personal leverage to earn more on personal funds than the return they actually require. Why is it not necessary to calculate the individual investor's weighted average cost of capital and only allow him to earn a return equal to it? The answer should be obvious.

A situation where individual investors can employ personal leverage so as to earn *more* than the return they actually require on personal funds is a situation of *disequilibrium* that cannot last for long in a competitive capital market. As long as the marginal investor can employ personal leverage and earn more on personal funds than he actually requires from an investment in the common stock of a holding company, there will be upward pressure on the price of the company's stock. As the price moves upwards, the market yield falls, and so does the return earned by the marginal investor on personal funds after paying the interest cost of the borrowed funds. The price will continue to rise, and the return on personal funds to the marginal investor will continue to fall, as long as the return earned on personal funds is greater than the return required. Equilibrium is restored when the return on personal funds earned by the marginal investor just equals the return he requires.

In equilibrium the market yield on the holding company's stock just equals the marginal investor's weighted average cost of capital. Since the competitive forces of the marketplace prevent the marginal investor from earning any more than his weighted average cost of capital on funds he has invested in the common stock of the holding company, there is no need to worry about the problem of "triple" leverage. But what is to keep a utility holding company from earning more than *its* weighted average cost of capital if the regulatory authorities choose to ignore double leverage? It is going to take more than bad economic logic parading as an argumentum reductio ad absurdum to prove that the double leverage concept is not valid.

Argument Five — It has been argued that the double leverage concept implies "a rigid, clearly traceable flow of funds which is not possible of accomplishment."* This is a curious argument that flies in the face of two incontrovertible facts: (1) The book value of the capital invested by the parent in a subsidiary is clearly and precisely identifiable; and (2) the parent's cost of capital which it must earn on any and all of its investments, including investments in subsidiaries, can also be clearly and adequately identified. These are the only a priori conditions that must be satisfied to apply the double leverage concept. It would be interesting to see someone try to tell the management of a holding company that the book value of its investment in a subsidiary cannot be clearly traced to the parent and therefore the subsidiary is free to use its retained earnings to pay dividends to other parties. If such an argument were ever to be upheld by a court of law we would all be justified in predicting the doom of the corporate enterprise system as we know it.

This argument — and others like it — is predicated upon the fallacy that the double leverage concept is valid only if the funds contained in the equity accounts of the subsidiary came directly from the parent. Thus Brown argues that double leverage is not valid because "none of the retained earnings of an operating subsidiary can be traced to the capital raised by a parent company." But the cost of equity is the same whether the equity was raised in a capital market or exists in the form of retained earnings. If a subsidiary retains a portion of its earnings, the earnings it retains are no less the capital of the parent than the capital recorded on its accounts as "paid-in." And the opportunity cost to the parent is the same whether the capital invested in the subsidiary is paid-in capital or retained earnings.

Argument Six — Professor Lerner's article (see footnote 2), the substance of which is set forth in his own words, contains serious flaws. He argues that:

> . . . the consolidated holding company enterprise can support more debt than the total of its individual operating parts, because the differences between the cash flows and risks of the operating companies tend to offset one another at the parent company level. . . . The additional debt of the parent arises only because of the ability and the willingness of the parent company itself to take advantage of the differences in the cash flows of its operating companies. . . . The additional debt, however, does involve additional risk which is borne entirely by the security holders of the holding company. Therefore, if the existence of this additional debt — which, in effect, is the "double leverage" of the double leverage argument — produces a return, that return should accrue to the security holders of the parent company since they have assumed the additional risk.

This is an absolutely incredible argument for an economist to make since it is predicated upon the assumption that capital markets are inefficient and incapable of pricing a holding company's stock so as to reflect all the risk inherent in an investment in the company's equity. Assume, with Professor Lerner, that a holding company takes advantage of the variability of cash flows and issues additional debt. As Professor Lerner correctly observes, this will result in additional (financial) risk to individuals investing in the holding company's stock.

Any other economist besides Professor Lerner would argue that as a result of this additional risk the equity investor will require additional return. In other words, the holding company's cost of equity, compared to what it was before it issued the additional debt, will increase. In a jurisdiction where the regulatory authorities apply the the double leverage concept this increase in the cost of equity will be fully reflected in the parent company's weighted average cost of capital and therefore in the return it is allowed to earn on an investment in a subsidiary. Professor Lerner's argument is that the holding company should be allowed to earn more than its cost of capital because it has incurred additional risk. The only situation that would justify such an argument is where a company's cost of capital does not increase with an increase in financial risk. The consensus of the financial community seems to be that capital markets are remarkably efficient. If so, the situation required to give any plausibility to Professor Lerner's thesis does not exist.

Summary and Conclusions

These are some of the arguments advanced against the double leverage concept. Given time, those who have an interest in opposing regulatory recognition of double leverage will think of others. They will all be directed towards the proposition that the relationship between a utility holding company and its subsidiaries is irrelevant to a proper determination of the return to be allowed its subsidiaries. But such is not the case. The rationale for regulation is to emulate competition. Under competition the net present value of marginal investment is zero. To achieve the same result regulation has adopted the cost-of-capital concept as a basis for rate of return regulation. Where this concept is correctly applied the net present value of investment in utility plant is zero. Where double leverage is ignored the holding company arrangement allows the utility to get out from under this traditional restraint. A consistent application of the cost-of-capital standard demands regulatory recognition of the effect of double leverage. The case for double leverage is so compelling that nothing in the armamentarium of those who would oppose it can ever refute it. Some states already recognize their responsibility to give effect to the existence of double leverage when determining a return for the subsidiary of a holding company.[7] Others will follow.

*The quote is from the original Michigan Bell order rejecting double leverage. See footnote 1, supra. The same argument is made by Brown.

[7]For a particularly lucid account of why one state commission adopted double leverage see the order of the Iowa State Commerce Commission in Re Hawkeye, footnote 4, supra. Other states that have adopted double leverage are Minnesota, Re Continental Teleph. Co. of Minnesota, Inc. (1976) 14 PUR4th 310; New Jersey, Re United Teleph. Co. of New Jersey (1976) 2 PUR4th 299; New York, Re Mid-state Teleph. Co., Inc. (1975) 10 PUR4th 88; and Wisconsin, Re General Teleph. Co. of Wisconsin (1960) 34 PUR3d 497.

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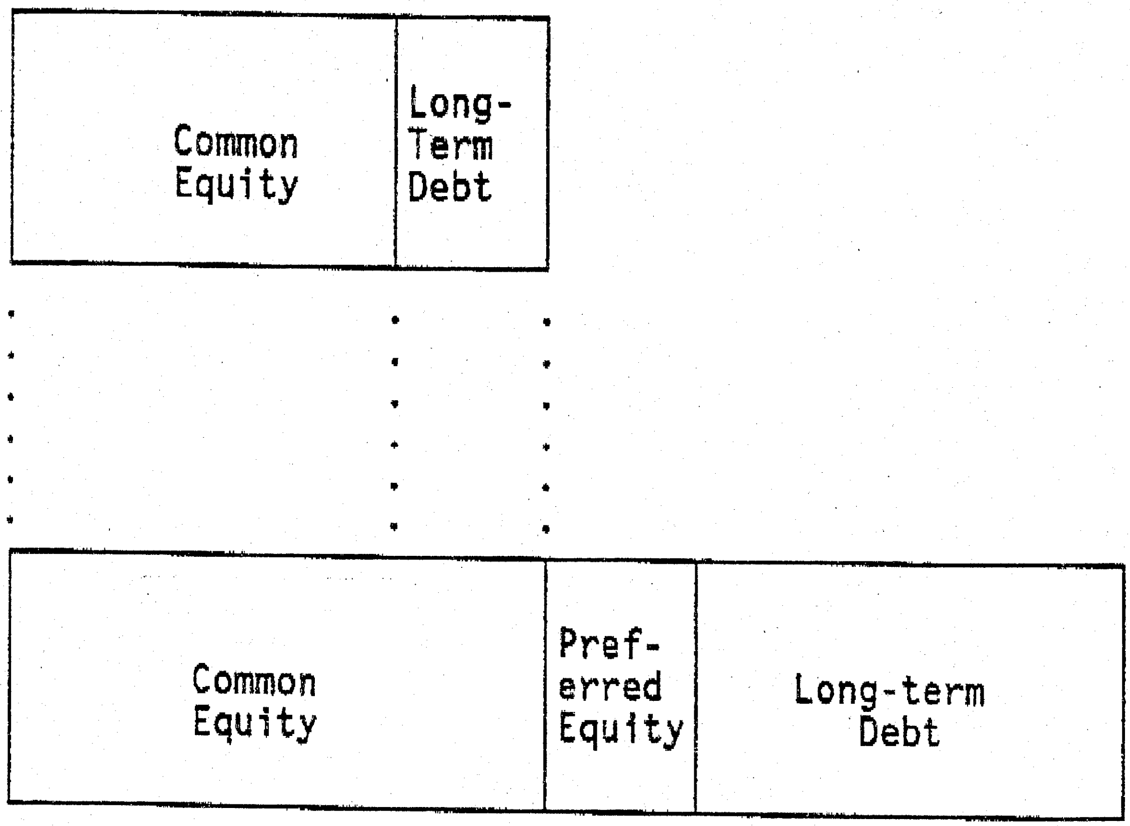

SUBSIDIARY

Volatility Panel Proposals: A Good Place to Start

By James B. Cloonan

The report of the NYSE Market Volatility and Investor Confidence Panel, on which I served, is out and as expected it has found numerous critics. The specific recommendations were, in many cases, compromises. I do not agree with all of the recommendations, but I do believe that they are a place to start. It is interesting that the number of critics claiming it went too far is about the same as the number claiming it didn't go far enough.

I tried to keep an open mind throughout the deliberations and I feel that most of the other panel members did as well. I learned a lot and my attitudes did change as a result of examining data and research.

I would like to go over the major issues relating to market volatility. While other topics that relate to investor confidence were discussed and recommendations were made, most of these are non-controversial.

However, before discussing the various courses of action that were evaluated, let me provide some background information.

First of all, study after study shows that there has been no increase in the volatility of the stock market in recent years, except for an increase in the number of days with high intraday volatility. Similar periods of high intraday volatility have occurred previously in the early 1970s and 1930s. But this intraday volatility does not usually have an effect on individual investors, since only those watching the market hourly would know it actually happened before it was over.

Even though the major victims of such intraday volatility are specialists and brokerage firms, it can have some negative impact on individuals. There are four ways that this can happen. First, news media emphasis on the intraday moves can make individuals think that long-term volatility is increasing. Second, even long-term investors sell sometimes, and a normal sell decision might get caught in the wild flurry of a single day. Third, stop orders can lose their effectiveness during this kind of volatility and these orders can be very useful for individuals who are not constantly watching the market. Fourth, the losses of specialists and market makers reduce liquidity in the marketplace. Even if intraday volatility cannot be controlled, it may be possible to address the specific problems affecting individuals, and therefore the report has called for examining new approaches to these problems.

Secondly, program trading is defined as the simultaneous buying or selling of 15 stocks with a value of over $1 million. About one-half of program trading is index arbitrage and the rest is the adjustment of portfolios for risk reasons and short- or long-term trading strategy purposes. It does not seem possible in a free economy to tell investors—institutional or individual—that they cannot buy or sell based on their own strategies. We can, however, slow the process, particularly in fast markets when computer-driven models react quickly to strong up or down moves and reinforce the direction of the move before normal countervailing forces can come into play. Restrictions on programs in fast markets have been recommended.

Index arbitrage must exist because there are multiple markets dealing with equities. It is not possible to have multiple markets without arbitrage. Even if it were outlawed, it would still take place, but market disruption would increase and profits would go offshore.

As it is, those involved in index arbitrage perform the function of keeping the markets orderly. They do across markets what specialists and market makers do within each market. The competition is severe and, for risk-free arbitrage, the profit is squeezed down to just over the T-bill rate. The futures market is quicker and more efficient than the stock market, and if the specialists could react more quickly to changes in futures, then the gaps between the markets might never widen enough to make index arbitrage possible. Steps in this direction

James B. Cloonan is president of AAII. His column is his own opinion and does not necessarily reflect the views of the AAII Journal.

have been recommended.

The existence of more efficient systems for implementing trades makes executions quicker. A piece of news can trigger the number of sales in a minute that used to be distributed over hours or days. These sudden moves appear dramatic because we are not used to them, but there is a reasonable argument that the quicker a destabilizing effect works through the system, the quicker normalcy returns. This could mean that in return for sudden intraday moves, long-term volatility will be reduced.

The only way back to the past would be to eliminate futures and options. At this point in time, with financial markets in place overseas, it doesn't seem possible to do that. Even if it were possible, I don't know if we really would want to do it. My best guess is that without futures, the reduced interest in the stock market would have the Dow 400 points lower. Because of futures, institutions can invest substantially more in equities than would be prudent without futures. A mutual fund that had to keep 5% liquid for redemption reserves can now be fully invested by using T-bills and futures for that 5%. The only disappointing aspect of this increased demand for equities is that it has only impacted S&P 500 stocks, but there may be more broadly-based indexes in the future.

Are there ways to reduce the negative effects of our current system without interfering with the positive effects? I believe so, and I believe that such steps have either been undertaken or are being considered, but constant evaluation is necessary.

Because so much publicity has been given to other possible solutions (I discussed them last January), let me review the more popular themes. Market halts, fast market restrictions on programs, encouraging corporations to add liquidity, and encouraging systems that would make the stock market and futures market react more quickly to one another have all been recommended.

The other popular recommended solutions are the uptick rule for short sales, margin changes, and restricting the short-term trading of exempt institutions by imposing taxes or otherwise.

The uptick rule is the easiest to analyze. The current rule restricts short sales to uptick or zero uptick trades —trades that are made when the stock price is the same or higher than the previous trade. The exception often quoted does not apply to program trading and program trades must abide by the rule. Short sales, however, are not generally involved in program trading. Stock is sold from inventory.

All the discussion of the relative margins on stocks versus futures has been oriented toward individual margins. However, individuals do not do programs. Their margin requirements have little effect on market volatility except that higher margins reduce liquidity and increase volatility. I am not, however, advocating reduced margins. Individual margins, I believe, should be set like any other loan or good faith deposit with the objective of reducing defaults.

Neither institutions, brokerage firms trading for their own account, market makers or specialists are bound by regular margins. The institutions, except for smaller hedge partnerships, don't use margin at all. Brokers, specialists, and market makers have different rules and it appears their margin and capital rules are about the same for futures, stocks, and options. Margins simply don't affect program trading.

Restricting the short-term trading of exempt institutions is still a possibility. At this point, I don't believe it is necessary, and a proposed "transaction tax" would have much the same effect.

In short, I guess I don't believe it is possible or desirable to try to go back to the past. We can't restrict technology. It seems far better to use our efforts to smooth out the problems that change creates rather than to try to prevent change.

proceeding within 30 days after the filing date. Proposed new or changed rates, charges, schedules, or regulations which contain energy efficiency expenditures and related costs which are incurred after July 1, 1990, for demand-side programs shall not be included in a rate-regulated utility's proposed tariff which relates to a general increase in revenue. A utility may propose to recover the costs of process-oriented industrial assessments not related to energy efficiency as defined in rule 199—35.2(476). The filing is not a contested case proceeding under the Iowa administrative procedure Act unless and until the board dockets it as a formal proceeding. No person will be permitted to participate in the filing prior to docketing, except that the consumer advocate and any customer affected by the filing, except as limited by subrules 22.12(1) and 22.13(1), may submit within 20 days after the filing date a written objection to the filing and a written request that the board docket the filing, which request the board may grant in its discretion. Such written objections and requests for docketing shall set forth specific grounds relied upon in making the objection or request.

7.4(5) *Letter of transmittal.* Three copies of all tariffs and all additional, original, or revised sheets of tariffs and the accompanying letter of transmittal shall be filed with the board and shall include or be accompanied with such information as is necessary to explain the nature, effect, and purpose of the tariff or additional, original, or revised sheets submitted for filing. Such information shall include, when applicable:

a. The amount of the aggregate annual increase or decrease proposed.

b. The names of communities affected.

c. The number and classification of customers affected.

d. A summary of the reasons for filing and such other information as may be necessary to support the proposed changes.

7.4(6) *Evidence.* Unless otherwise authorized by the board in writing prior to filing, a utility must when proposing changes in tariffs or rate schedules, which changes relate to a general increase in revenue, prepare and submit with its proposed tariff the following evidence in addition to the information required in 7.4(11). The board shall act on requests for waivers not later than 14 days after filing of those requests. If no action is taken on a request for waiver, it shall be deemed denied.

a. Factors relating to value. A statement showing the original cost of the items of plant and facilities, for the beginning and end of the last available calendar year, any other factors relating to the value of the items of plant and facilities the utility deems pertinent to the board's consideration, together with information setting forth budgeting accounts for the construction of scheduled improvements.

b. Comparative operating data. Information covering the latest available calendar year immediately preceding the filing date of the application.

(1) Operating revenue and expenses by primary account.

(2) Balance sheet at beginning and end of year.

c. Test year and pro forma income statements. Schedules setting forth revenues, expenses, net operating income of the last available calendar year, the adjustment of unusual items and by adjustment to reflect operations for a full year under existing and proposed rates.

d. Additional evidence for rural electric cooperatives. In addition to the foregoing evidence, a rural electric cooperative shall file schedules setting forth utility long-term debt and debt costs, accrued utility operating margins and other components of patronage capital, the cooperative's plan to refund utility patronage credits, the ratio of utility long-term debt to retained utility operating margins, the times interest earned ratio, the debt service coverage, authorized utility construction programs, utility operating revenues from base rates, and utility operating revenues from power cost adjustment clauses.

e. Additional evidence for investor-owned utilities. In addition to the foregoing evidence, an investor-owned utility shall file, at the same time the proposed increase is filed, the following information. For the purposes of these rules, "year of filing" means the calendar year in which the filing is made. Unless otherwise specified in these rules, the information required shall be based upon the calendar year immediately preceding the year of filing.

(1) Rate base for both total company and Iowa jurisdictional operations calculated by utilizing a 13-month average of month-ending balances ending on December 31 of the year preceding the year of filing, and also calculated on a year-end basis, except for the cash working capital component of this figure, which will be computed on the basis of a lead-lag study as set forth in subparagraph (5).

The rate base for the Iowa jurisdictional operations of rate-regulated telephone utilities will be computed on the basis of actual month-end balances which have been verified and adjusted to reflect the results of true-up procedures. True-up is the comparison of actual usage for each deregulated service with any previous estimates of deregulated usage for a given time period for the purpose of adjusting rate base and income statement allocations between deregulated and regulated services. Trued-up month-end balances for each deregulated service will be completed through the end of the test year prior to the date of filing a general rate case.

(2) Revenue requirements for both total company and Iowa jurisdictional operations to include: operating and maintenance expense, depreciation, taxes and return on rate base. The Iowa jurisdictional expenses of rate-regulated telephone utilities will be adjusted to reflect allocation factors which have been computed as a result of actual month-end balances which have been verified and adjusted to reflect the results of true-up procedures. True-up is the comparison of actual usage for each deregulated usage for a given time period for the purpose of adjusting rate base and income statement allocations between deregulated and regulated services. Trued-up month-end balances for each deregulated service will be completed through the end of the test year prior to the date of filing a general rate case.

(3) Capital structure calculated utilizing a 13-month average of month-ending balances ending on December 31 of the year preceding the year of filing, and also calculated on a year-end basis.

(4) Schedules supporting the proposed capital structure, schedules showing the calculation of the proposed capital cost for each component of the capital structure and schedules showing requested return on rate base with capital structure and corresponding capital cost.

(5) Cash working capital requirements, including a recent lead-lag study which accurately represents conditions during the test period. For the purposes of this rule, a lead-lag study is defined as a procedure for determining the weighted average of the days for which investors or customers supply working capital to operate the utility.

(6) Complete federal and state income tax returns for the two calendar years preceding the year of filing and all amendments to those returns. If a tax return or amendment has not been prepared at the time of filing, the return shall be filed with the board under this subrule at the time it is filed with the Internal Revenue Service or the state of Iowa Department of Revenue and Finance.

(7) Schedule of monthly Iowa jurisdictional expense by account as required by chapter 16 of the board's rules unless, upon application of the utility and prior to filing, the board finds that the utility is incapable of reporting jurisdictional expense on a monthly basis and prescribes another periodic basis for reporting jurisdictional expense.

(8) For gas, electric and water utilities, a schedule of monthly consumption (units sold) and revenue by customer-rate classes, reflecting separately revenue collected in base rates and adjustment clause revenues. For telephone companies, a rate matrix as set forth in the company's annual report (page B-16), shall be filed along with a statement of the total amount of revenue produced under the rate matrix.

(9) Schedules showing that the rates proposed will produce the revenues requested. In addition to these schedules, the utility shall submit in support of the design of the proposed rate a narrative statement describing and justifying the objectives of the design of the proffered rate. If the purpose of the rate design is to reflect costs, the narrative should state how that objective is achieved, and should be accompanied by a cost analysis that would justify the rate design. If the rate design is not intended to reflect costs, a statement should be furnished justifying the departure from cost-based rates. This filing shall be in compliance with all other rules of the board concerning rate design and cost studies.

(10) All monthly or periodic financial and operating reports to management beginning in January two years preceding the year of filing. The item or items to be filed under this rule include: (a) reports of sales, revenue, expenses, number of employees, number of customers, or similar data; (b) related statistical material. This requirement shall be a continuing one, to remain in effect through the month that the rate proceeding is finally resolved.

Notwithstanding other provisions concerning the number of copies to be filed, one copy of each report shall be filed under this rule.

(11) Schedule of monthly tax accruals separated between federal, state, and property taxes, including the methods used to determine these amounts.

(12) Allocation methods, including formulas, supporting revenue, expense, plant or tax allocations.

(13) Schedule showing interest rates, dividend rates, amortizations of discount and premium and expense, and unamortized 13 monthly balances of discount and premium and expense, ending on December 31 of the year preceding the year of filing, for long-term debt and preferred stock.

(14) Schedule showing the 13 monthly balances of capital stock expense associated with common stock, ending on December 31 of the year preceding the year of filing.

(15) Schedule showing the 13 monthly balances of capital surplus, separated between common and preferred stock, ending on December 31 of the year preceding the year of filing. For the purpose of this rule, capital surplus means amounts paid in that are less than or are in excess of par value of the respective stock issues.

(16) Stockholders' reports, including supplements for the year of filing and the two preceding calendar years. If such reports are not available at the time of filing, they shall be filed immediately upon their availability to stockholders.

(17) If applicable, securities and exchange commission Form 10Q for all past quarters in the year of filing and the preceding calendar year, and Form 10K for the two preceding calendar years. If these forms have not been filed with the securities and exchange commission at the time the rate increase is filed, they shall be filed under this subrule immediately upon filing with the securities and exchange commission. This requirement is not applicable for any such reports which are routinely and formally filed with the board.

(18) Any prospectus issued during the year of filing or during the two preceding calendar years.

(19) Consolidated and consolidating financial statements.

(20) Revenue and expenses involving transactions with affiliates and the transfer of assets between the utility and its affiliates.

(21) A schedule showing the following for each of the 15 calendar years preceding the year of filing, and for each quarter from the first quarter of the calendar year immediately preceding the year of filing through the current quarter.

Earnings, annual dividends declared, annual dividends paid, book value of common equity, and price of common equity (each item should be shown per average actual common share outstanding, adjusted for stock splits and stock dividends).

Rate of return to average common equity.

Common stock earnings retention ratio.

For common stock issued pursuant to tax reduction act stock ownership plans, employee stock option plans, and dividend reinvestment plans: net proceeds per common share issued, and number of shares issued and previously outstanding at the beginning of the year. This shall be set forth separately for each of the three types of plans, and reported as annual aggregates or averages.

For other issues of common stock: net proceeds per common share issued, and number of shares issued and previously outstanding for each issue of common stock.

(22) If the utility is applying for a gas rate increase, a schedule for weather normalization, including details of the method used.

(23) All testimony and exhibits in support of the rate filing attached to affidavits of the sponsoring witnesses. All known and measurable changes in costs and revenues upon which the utility relies in its application shall be included.

Unless otherwise required, an original plus ten copies of all testimony and exhibits, and four copies of all other information, shall be filed. Three copies of each of the preceding items shall be provided to the consumer advocate. In addition, two electronic copies of each computer-

So Long, Calvin Coolidge

Meter Reading Approaches the 1990s Promising a Pivotal Market for Communications Infrastructure

By Stephen N. Brown

Federal and state regulators must become knowledgeable about Automatic Meter Reading (AMR) and all that it entails. After all, AMR is a pivotal market that will shape the nation's communications infrastructure by determining whether energy and water industries move toward an intelligent, public-switched communication network or toward radio-based personalized communication networks.

The junction lies in the eventual replacement of roughly 250 million electric, gas, and water meters in the United States, nearly all of which reflect the technology of the 1920s: they must be read manually, they are incapable of implementing time-differentiated rates, they cannot communicate with anything, and their information storage capability is nil. They will be replaced by devices embodying today's technology, and that will be compatible with the nation's communication infrastructure.

Radio Networks or Wired Networks?

The infrastructure is being shaped by the century-old competition between radio networks and wired networks. Radio-based cellular and microwave technology use the electromagnetic spectrum and offer the promise of personalized communication networks (PCNs) along with decentralized ownership and splintered control of the nation's communication infrastructure.

The AMR market already reflects the struggle over market position and the dichotomies between radio and wired technologies, and between unilateral control and integrated control. AMR products available today encompass various radio offerings, including one combination of spread-spectrum signalling with a power line carrier, as well as telephone-inbound/outbound strategies.Telephone-based products require cooperation between the local exchange carriers and the utility; the spread-spectrum/power-line device is unilaterally operated by the utility. However, there is no dominant AMR strategy or product in the electric, gas, and water industries; also, they have no organized strategy on how to migrate from a 1920's-vintage metering technology to the 1990s. The AMR market today is still immature, disorganized, and untapped, but loaded with potential.

Why?

Because replacing 250 million meters, not to mention possible markets abroad, represents a major demand for new manufactured products that embody new communication technology.

Capable Networks for Energy Industries

More capable networks are needed by the electric utility industry, which is under intense pressure to adopt energy efficiency strategies requiring load monitoring, load management, incentive rates, and perhaps eventually real-time pricing.AMR is essential for all these strategies. Therefore, regulators should advocate AMR investments in energy-utility networks, whether radio or cable-based, that:

- have scale economies;
- possess multi-functionality;
- can easily implement rate structure changes;
- are consistent with open-architecture principles;
- avoid redundancy and duplication of another local utility's investments.

The regulatory community should take the lead in advocating economic cooperation between different utility industries—not only for the potential economic benefits but also because the utilities and American business in general do not value economic cooperation.

Shorter Replacement Cycles

The application to AMR and the regulatory process is this: Regulated industries should be responsive to continual product improvements in AMR. Regulators should not expect AMR products to have a 30- to 40-year depreciation schedule, nor should they expect utilities to make automation investments and then not replace them for decades. Product replacements are likely to occur in shorter cycles such as eight to twelve years.This is true for either radio or wired technologies.

An important feature of continual product improvement is the role of customer feedback in guiding incremental improvements to the product after it has been introduced. This suggests a need for continual cooperation between utilities and AMR manufacturers. In an intelligent network, product improvement means software improvements to create and access data bases that are centralized with regard to a local access transport area (LATA). Without an intelligent network, data bases are located in each local exchange. There are approximately 120-150 LATAs in the country along with several thousand local exchanges. Centralizing data bases in LATAs rather than local exchanges reduces the development cycle for new services from years to months.

However, the communications industry has no plans to develop processing capability in digital central office switches.An intelligent network offering speed but lacking distributed processing may have little value to electric utilities. Their long-term planning is evolving toward the distributed utility concept: the electrical distribution system becomes the focus of planning, processing, reliability, and power quality control. Distribution control was a sideline issue when central station economies of scale dominated the electric power industry, but this situation has changed.

The new emphasis is on the distribution sector, which is ready for massive applications of technology that control and manage the end user's consumption. AMR software and hardware are aimed at the distribution sector; load management is a distribution function.AMR products will also have load management capability. Consequently, there's a clear need for processing capability.But where will that capability be located, at the company's headquarters or at selected points in the field, such as a central office?

The processing capability should be located in the field, making the logical choice for processing in an intelligent network digital central office switches. All organizations, including utilities, would probably recoil at the idea of a digital central office that processes data, fearing for the data's privacy and reliability. Appropriate encryption and validation procedures would make processing viable at the central switch, and provide two separate opportunities for cooperation between a phone company and an energy utility: where the local company does not have a digital switch, coordination between the two utilities could result in the installation of a new digital switch. Where a digital switch already exists, joint investment in its distributed processing capability will expand the intelligent network's scope. A utility's data bases could be placed in the central switch and accessed on a LATA basis. Without this capability, the intelligent network may be a case of bandwidth overkill for AMR and load management functions, with no thought given to the network's potential for time differentiated pricing or other add-on services for utilities.

Property and Profit

An intelligent network's product improvement is tied directly to software, a concrete, easily recognized aspect of the intelligent network.But in a radio network product improvement is amorphous because a frequency cannot be "owned", and there are no codified private property rights regarding the spectrum. Government steps in to allocate the spectrum.In a competitive setting, lack of property rights in the spectrum makes the innovator's profit stream far less secure than for the intelligent network's innovator.In a competitive setting property rights protect the profit stream created by the innovator. For this reason, an intelligent network is more likely to sustain a high rate of innovation than a radio network.In fact, one of the more notable innovations in radio technology thrives on the absence of property rights. Spread spectrum technology hops across adjacent radio frequencies to mask the content of a radio message.While this is successful in military applications, the technology has not yet penetrated the commercial markets to a significant degree.

Product improvement is important for radio-based AMR manufacturers. They will have to demonstrate their product's potential for broad application over time before they can capture the utility industry as a long-term AMR customer.

Dr. Stephen N. Brown is Chief, Bureau of Energy Efficiency, Auditing, and Research Utilities Division, Iowa Department of Commerce. This paper was presented at the New Mexico State University's Center for Public Utilities: Current Issues Challenging the Regulatory Process held in Santa Fe, New Mexico March 11, 1992.

Opinion

No Second Time Around for AMR

By Stephen Brown, AMRA Treasurer
Iowa Department of Commerce

David Gorton's editorial in AMRA's January newsletter ["Looking Back to See the Future," p. 2] conveyed the notion that AMR's problems are no different today than they were 30 years ago. To an extent, he is right. AMR's problems are perennial because the utility industry's retail business environment has been remarkably stable. But the time will come when the environment changes, allowing a permanent fix for the infirmities of the AMR market.

Utilities have a growing need for accurate and prompt measurement of consumption. This is not caused by a sense of righteous conversion to AMR. Cold, hard self-interest is the reason. The electric and gas utilities, in particular, are more interested in AMR today because they face the prospect of competition in all phases of their business. Competition implies uncertainty about profit margins and a need for detailed knowledge of the retail market. Good information acquired through AMR will make the difference between success and failure in a competitive market.

Standard and Poor's Corp., a major financial ratings firm, believes that competition is making the electric business very risky. Consequently, the firm set new financial standards that may reduce credit ratings for one-third of the nation's electric utilities. This has never happened before. The industry's new competitive environment may compel utilities to install AMR equipment that embodies rapid communication and sophisticated measurement. Thus, the recycling of AMR's familiar problems may truly come to a final end.

However, Gorton's editorial shows the same thought being voiced in 1967: "AMR has been a 'want' of the electric utilities for many years but now is rapidly becoming a 'must.'" That statement was wrong in 1967, but it's right today. If you want to know why, read an insightful article by AMRA member Roger Levy. He cowrote *Re-engineering DSM: Opportunities Through Information and Integration*, which appears in last November's issue of *The Electricity Journal.* Levy explains why the electric utility industry failed, in general, to implement automation procedures regarding measurement and communication in the retail market. The dominant reason, says Levy, is "most ... technical and procedural designs incorporate implicit and explicit compromises to make sure that programs cause little disruption and conform as closely as possible to the operating practices and features of existing utility company business management and information systems."

In short, AMR and all automation systems have the potential to create ripple effects throughout a company. If unwilling to live with these or take advantage of them, the company constrains the automation project, cutting it here and tweaking it there until the project is reduced to a shadow, drained of its promise and potential.

In Levy's words, "What starts out as a 'logical compromise' ... artificially limits how ... communication, measurement and control technologies might be used to modernize existing utility systems and practices."

In today's market, many industries depend on rapid information flow for marketing, cost cutting and competing, including: the overnight package delivery industry, the vending machine business, the liquid fuels business of propane and butane delivery, and all "just-in-time" production and inventory businesses. These enterprises have made every effort to automate because it's vital to their success.

In 1967, automation at the retail level didn't mean anything to the utility industry, and AMR was a nonevent. That era is over. The AMR industry should take advantage of the present, push on all fronts and think big.

The advice of Daniel Burnham is appropriate. He was a urban planner who, in 1900, redesigned the cities of Chicago and Washington, D.C. He told the cities' leaders, "Make no small plans, they do not stir men's imagination."

AMR pilot projects have seen their day. The technology won't mature if it's forever limited to trials. Its true potential lies in full-scale, utilitywide projects, and now is the time to pursue them.

Stephen Brown works for the Iowa Department of Commerce, which is based in Des Moines. He also serves as the treasurer of AMRA.

Opinion

DOE Proposal Trivializes AMR

By Stephen Brown
Iowa Department of Commerce

Automatic meter reading (AMR) received much needed attention when Congress enacted the Telephone Disclosure and Dispute Resolution Act of 1992. It directed the U.S. Department of Energy (DOE) to consider a government demonstration project involving utility communications and AMR.

Last March, the DOE opened docket CE-NOI-93-001, an inquiry meant to implement Congress' directive. After consultation with the U.S. Commerce Department, the DOE released its final report, *Proposal for Demonstrating the Potential of Innovative Communications Equipment and Services for Utility Applications*, on Sept. 2. [See related article on page 3.] In it, the DOE recommends against a "use of federal funds" to develop an AMR or energy-management demonstration project because "it would duplicate demonstrations already planned by utilities."

Despite this reasonable conclusion, the final document is disappointing. It could have been a means for the DOE to show Congress that meter reading and utility communication are vital functions in the American economy. Instead, the DOE sent Congress a message that trivializes AMR.

The report accepts without question a cliched, moss-backed argument used for years to stifle innovation in metering, utility pricing and communication: "Presently the main limitation on automatic meter reading is cost. According to the Edison Electric Institute in their response, a survey of their members shows that it only costs between 30 cents and 60 cents per customer per month to read the meter manually for typical customers...". When Congress reads this, they will wonder why anyone would bother with AMR since manual reading is cheaper than a phone call.

The report is flawed because the agency's worldview is confined to the Washington Beltway. Twenty-seven respondents filed comments on CE-NOI-93-001. The DOE apparently thinks only two had opinions that are worthy of Congress' attention. The DOE highlights the filings of the Edison Electric Institute and the Utility Telecommunications Council, two of the oldest guards in Washington. The report does not refer to the opinions of the other 25 respondents — vendors, phone companies, cable companies, utilities and consultants. A balanced report would have drawn from many respondents, not just two. It would have shown the fallacy of the "manual meter reading is cheap" argument.

Manual meter reading is cheap because it is an almost worthless service. It gives practically nothing to consumers and utilities. The inadequacy of meter reading and its failure to facilitate economic decision making by consumers is shown by the popularity of balanced-billing for gas, water and electric utilities.

In balanced-billing, a customer's annual bill is estimated and divided by 12. The result is the customer's monthly bill. At the end of one year, the difference between actual and estimated consumption is reconciled, the customer receives a credit or debit, and the cycle starts again. Millions of consumers use balanced-billing. In short, the payment for consumption of gas, water and electricity in the United States is little different from making a premium payment for insurance. The success of balanced-billing shows the only effective use of manual meter reading — reconciling the customer's estimated annual consumption against actual consumption once a year in order to balance a company's annual cash flow.

It is a mystery why the DOE gladly accepts the cheap meter-read argument and then passes it on to Congress as an unquestioned truth. Consumers need the opportunity and the tools to treat their energy and water purchases like any other commodity or service. AMR is the tool, and a time-sensitive utility price is the opportunity. These will create new patterns of energy and water use, perhaps allowing the next generation of Americans to mitigate and avoid costs for such things as the safe disposal of nuclear fuel used in power plants, which is now estimated at $45 billion.

With AMR, the next generation will shop for the right time to buy energy, from the right source and at the right price — just like it shops for the right groceries and right times to travel. It's time for the utility industry's metering practices to measure up to the 1990s and the next century.

The DOE's report could have sent these messages to Congress while still arriving at the same conclusions. Instead, Congress will now dismiss the issue as trivial.

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ECONOMIC INCENTIVES FOR NUCLEAR PLANT PERFORMANCE: A STATE PERSPECTIVE

BY

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DELIVERED AT THE NRC'S STATE LIAISON OFFICERS' MEETING: REGION III
GLEN ELLYN, ILL., SEPTEMBER 29, 1988

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INTRODUCTION

I had the opportunity to listen to Nuclear Regulatory Commissioner Ken Rogers' presentation at the July 25th meeting of NARUC's subcommittee on nuclear issues. Commissioner Rogers clearly takes the position that capacity factors can be a disincentive to the safe operation of a nuclear power plant when they are used as a sole measure of the plant's overall economic performance. Of course, the Commissioner's stance accurately represents the Nuclear Regulatory Commission's (NRC's) basic opinion regarding target capacity factors and their role in the incentive programs established by state regulatory bodies.

I'm a senior staff member of a state regulatory body, the Iowa Utilities Division, a group that provides line and staff support to the Iowa Utilities Board, a body composed of three appointed officials, the decision-makers who set policy. **I do not speak for their policy views on incentive programs.** But I am in the position to describe why nuclear plant performance is becoming an issue in Iowa, to make my own professional assessment of the capacity factor issue, and to offer a compromise measure, one that may satisfy the concerns of the NRC and those of state regulatory agencies engaged in economic incentive programs.

NUCLEAR POWER IN IOWA

Nuclear power plants provide approximately 25% of the net electrical generation devoted to consumption in Iowa. The plants are: Cooper, wholely owned and operated by Nebraska Public Power, but one-half of the net output is committed to the Iowa Power & Light Company; Duane Arnold, operated by Iowa Electric Light & Power Company, but jointly owned with two rural electric organizations; and Quad Cities Units 1 and 2, operated by Commonwealth Edison, but jointly owned with Iowa-Illinois Gas & Electric Company.

Nuclear plants are normally operated at a nearly constant level of output during most on-line hours, the exception being those on-line hours either immediately prior to a planned shut-down or during coast-down at the end of the fuel cycle. But the Utilities Division Staff found that Cooper and Duane Arnold substantially deviated from this pattern; from 1983 through

1986 both plants appeared to swing with load rather than operating in the base-load fashion characteristic of most other nuclear plants in the country. Table 1 is a comparison of Duane Arnold and Cooper utilization to utilization of nuclear plants in states adjacent to Iowa. For all four years these two plants were consistently near the bottom of the scale. Table 2 is a similar comparison for nuclear plants in the Mid-Continent Area Power Pool (MAPP), and Cooper and Duane Arnold again fall to the bottom of the scale. Tables 3 and 4 are similar comparisons using all the nuclear plants.[1]

All of this descriptive information substantiates the idea that these two plants, unlike most others in the country, were not being extensively base loaded. This is significant because of the very low fuel costs involved: between 6 and 9 mills per kilowatt-hour at both plants in comparison to costs of 13 to 15 mills at the large coal-fired plants in the state. The very obvious question is: why not increase the output at the nuclear plants as a substitute for the more expensive coal output? This issue is even more puzzling because one of the state's base-load coal fired plants has greater utilization than either Cooper or Duane Arnold during the same time frame. The Iowa Utilities Board ordered an investigation into this issue; interrogatories were sent to the two Iowa companies involved, and responses are expected in mid-October.

This approach appears to be retrospective, but it should also be viewed as a planning consideration. Federal acid rain legislation could have a negative impact on eight major generating plants in Iowa. If and when such legislation becomes law, compliance would most likely require curtailed output at some or all of these plants. As a group, the plants provide 4,600 megawatt hours (MWH) of the state's net electrical output, about 21 percent of the total net output. In addition, the plants' average number of annual service hours exceed 7,000, and the average hourly output is 82 megawatts (MW). Improved performance at the nuclear plants will alleviate some of the negative consequences of compliance with the new legislation. This is a primary reason why nuclear power plant performance in Iowa will be more important in the future.

THE CAPACITY FACTOR ISSUE

Given the scenario just described, how should a regulatory body proceed with the development performance evaluation? A quick answer, but one that would disturb the NRC, would be to use capacity factors. As most of you know, a capacity factor is a composite measure of a plant's availability and output level. If availability falls or if output declines, the capacity factor drops. The NRC's objection to capacity factors is simple but cogent: use of the factor encourages a company to run a nuclear plant when it should be shut down for periodic and preventive maintenance. Therefore, capacity factors lead to incremental deterioration of the plant with a cumulative effect on safety. New York Attorney General Robert Abrams expressed this sentiment when criticizing the New York PSC's incentive program: "A company striving to meet a capacity-factor target would be tempted to ignore or downplay the seriousness of safety problems."

This argument is aimed at state regulatory agencies. These organizations have a direct and large effect on the financial well-being of the utilities involved with the nuclear plants. From a financial view, the state bodies have a much greater impact on the companies than does the NRC. For this reason, state agencies can have substantial influence on how the companies manage nuclear plants. In fact, several states have chosen to exercise their influence, and despite the concerns of the NRC, have adopted incentive programs that include capacity factors. These states include New York, New Jersey, Florida, Virginia, and North Carolina among others. The contention and fractiousness over economic incentives and regulation is quite visible.

For example, a July 1988 Electrical World article summarized a nuclear plant survey conducted by the Reliability Engineering Department of Westinghouse Electric:

> ...organizational and external factors have a far stronger effect on availability of US reactors than physical attributes, such as age, reactor type, or nuclear-steam-supply-system vendor...Economic regulation sometimes hinders preventive-maintenance initiatives and plant equipment upgrades, the report concluded. "On the state level, there appears to be a widespread lack of understanding by utility commissions of the importance of nuclear power..."

The other side of the coin is illustrated by a December 1985 article appearing in the New York Times:

> ...(S)tate regulators seem unimpressed with the NRC's concerns and suggestions. "This is a political process," said one state regulator, adding that the NRC's protestations about the deleterious effect of financial incentive programs on reactor safety are "a nice smokescreen."

There appears to be disagreement between many state regulatory authorities, the nuclear power industry, and the NRC over the use of incentive programs and capacity factors. The most important question here is not who's right, but is there an alternative, one that is tenable for all concerned parties?

I believe that the answer lies in a composite measure that incorporates three ideas: (1) the utilization ratio concept illustrated in Tables 1 through 4; (2) service hours; and (3) reactor trip rates, referred to more formally as Reactor Protection System Actuation Rates.

DEVELOPING A COMPOSITE MEASURE

The utilization ratios in Tables 1 through 4 exclude hours when the plant is not in service, and therefore provide a simple indication about the kind of loading that prevails at the nuclear plant. The ratios are useful because they indicate if an economic dispatch problem is present. An economic dispatch problem is clearly not a plant performance problem, but this distinction would be hidden by capacity factors. By mixing availability and output level, capacity factors fail to pinpoint and isolate system problems from plant problems.

However, utilization ratios shed no light on plant availability; they are useless in this regard. Plant availability should be synonymous with service hours; this method is simple, clear, and avoids any confusion that might be caused by using capacity factors as a surrogate measure for availability. But there is an important point here; if capacity factors should not be used in an economic incentive program, then how can the capacity factor concept be legitimately used by generation planners when they're assessing the economic feasibility of a new plant? The link between capacity factors used for planning and actual capacity factors is shown in a February 1987 decision by the New Jersey Board of Public Utilities. The following is taken from the decision and order in Docket ER85121163.

> Nuclear plants are constructed with the expectation that their high capital costs will be offset by their low operating costs, thereby providing an economical, year-round energy supply to ratepayers. At the time the decisions were made to construct each of the Company's five operating nuclear plants - Salem I, Salem II, Peach Bottom II, Peach Bottom III and Hope Creek I- they were projected to perform at approximately 80% capacity factors. These projections were subsequently revised downward at the time construction commenced and again at the time of initial commercial operation. Despite these projections, the plants (exclusive of Hope Creek) have not met performance expectations and have been plagued with prolonged outages. The Company reported that the lifetime cumulative capacity factor for Salem I is 51.3%, Salem II - 47.7%, Peach Bottom II - 53.8% and Peach Bottom III - 60%. Further, plant operations have been characterized by wide swings in performance as evidenced by Salem II's 8% capacity factor in 1983 and Salem I's 95% capacity factor in 1985. Thus, ratepayers have been saddled with the cost burden of the plants' high fixed costs in base rates and expensive replacement power costs incurred as a result of substandard nuclear performance ... It is this history of uneven and substandard nuclear performance, its attendant cost burden to ratepayers and the Company's increasing reliance on nuclear generation that gives rise to the need for nuclear performance standards.

Repudiating capacity factors in an economic incentive program also means repudiating them in the generation planning and economic feasibility stage. How is this contradiction resolved to create a workable incentive program, one that also addresses the concerns of the NRC and the criticism of capacity factors voiced by New York State Attorney General, Robert Abrams, mentioned earlier? I believe the answer lies in the use of reactor trip rates.

The concept is clearly explained in a well-documented paper authored by David Dietrich of Technical Analysis Corporation. He makes several points in his paper, and I'm going to highlight just two of them because they're useful in this forum. The author makes this statement:

> An "RPS actuation with control rod motion" -- the standard terminology meaning reactor scram or shutdown -- results in lower economic efficiency because the plant is taken off line. Such an RPS actuation also results in a lower level of safety because the event presents a challenge to safety systems and operating staff that must bring the reactor to a safe condition.

With this comment Mr. Dietrich is establishing a connection between a reactor trip and economic efficiency; the greater the number of trips the lower the overall efficiency. In the next statement the author points out how well reactor trip rates coincide with the NRC's policy goals.

> The NRC has had a formal program to reduce trip frequency since 1984 and every year has seen a gradual reduction in trip rates. The NRC has concluded that "a reduction in the frequency of challenges to plant safety systems should be a prime goal of each licensee." It also finds that large reductions in the risk of an anticipated transient without scram (ATWS) can be achieved by reducing the frequency of transients that call for RPS operation. A reduction in the RPS actuation rate, the goal of the proposed incentive program criterion, is not only consistent with formal NRC policy. It is formal NRC policy.

However, reactor trip rates are not complete substitutes for capacity factors; although the two items are inversely correlated with each other, the correlation is not perfect. David Dietrich points out that while low trip rates are accompanied by high capacity factors and vice-versa, there are also instances where high capacity factors and high trip rates accompany each other. Based on this observation, my conclusion is that reactor trip rates alone should not be the only criteria to evaluate the economic performance of a nuclear plant.

CONCLUSION

In my opinion an economic incentive program should explicitly include reactor trip rates because they are useful and prudent, as well as being responsive to the concerns of the NRC. But I continue to believe that utilization levels and the number of plant service hours should also be a part of an incentive program. The exact weight given to each component would be a matter for the policy makers. The conceptual framework provided here represents a middle road, one that does not rely on a single measure to evaluate performance. An incentive program focusing on reactor trip rates, utilization levels, and service hours provides a workable alternative to reliance on target capacity factors and is a solution to the problem I mentioned earlier: where a company or industry repudiates capacity factors as a method of economic evaluation even though generation planners used capacity factors to justify economic feasibility for the plants in question. Use of the composite measure put forth in this paper would certainly recognize the interests of the ratepayers, the companies, and the concerns for safety expressed by the NRC.

TABLE 1

Comparison of Cooper and Duane Arnold Utilization to Utilization of Nuclear Plants in States Adjacent to Iowa for 1983-1986.

Plant No.	Year	Plant Name	State	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MW) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
1.	1983	Palisades	MI	812.00	635.00	3,769,958	5,283.60	713.52	112.37%
2.	1986	Kewaunee	WI	560.00	503.00	3,854,674	7,515.20	512.92	101.97%
3.	1985	Kewaunee	WI	560.00	503.00	3,699,176	7,214.70	512.73	101.93%
4.	1984	Kewaunee	WI	560.00	503.00	3,810,000	7,528.40	506.08	100.61%
5.	1984	Point Beach #1	WI	524.00	485.00	3,109,208	6,380.00	487.34	100.48%
6.	1983	Kewaunee	WI	560.00	503.00	3,706,928	7,335.80	505.32	100.46%
7.	1985	Point Beach #1	WI	524.00	485.00	3,354,176	6,919.30	484.76	99.95%
8.	1986	Point Beach #1	WI	524.00	485.00	3,770,070	7,787.60	484.11	99.82%
9.	1985	Point Beach #2	WI	524.00	485.00	3,603,081	7,491.30	480.97	99.17%
10.	1985	Palisades	MI	812.00	730.00	5,301,797	7,344.40	721.88	98.89%
11.	1986	Point Beach #2	WI	524.00	485.00	3,417,550	7,188.30	475.43	98.03%
12.	1984	Point Beach #2	WI	524.00	485.00	3,512,373	7,406.60	474.22	97.78%
13.	1983	Point Beach #2	WI	524.00	495.00	3,016,298	6,247.60	482.79	97.53%
14.	1984	Cook #2	MI	1,133.00	1,060.00	5,364,363	5,198.70	1,031.87	97.35%
15.	1983	Cook #2	MI	1,133.00	1,060.00	7,013,579	6,838.40	1,025.62	96.76%
16.	1986	Wolf Creek #1	KS	1,250.00	1,128.00	6,966,063	6,418.50	1,085.31	96.22%
17.	1986	Zion #2	IL	1,098.00	1,040.00	7,334,233	7,372.00	994.88	95.66%
18.	1984	Palisades	MI	812.00	635.00	811,549	1,336.30	607.31	95.64%
19.	1984	Callaway #1	MO	1,188.00	1,120.00	323,023	302.50	1,067.84	95.34%
20.	1986	Big Rock Pt. #1	MI	60.00	64.00	506,148	8,361.70	60.53	94.58%
21.	1985	Wolf Creek #1	KS	1,250.00	1,128.00	2,942,100	2,771.60	1,061.52	94.11%
22.	1984	La Crosse	WI	65.00	48.00	318,604	7,067.30	45.08	93.92%
23.	1984	Zion #2	IL	1,098.00	1,040.00	5,986,311	6,180.00	968.66	93.14%
24.	1983	Zion #2	IL	1,098.00	1,040.00	6,181,965	6,406.60	964.94	92.78%
25.	1984	Cook #1	MI	1,152.00	1,020.00	7,550,755	8,017.80	941.75	92.33%
26.	1983	Cook #1	MI	1,152.00	1,020.00	5,286,839	5,630.80	938.91	92.05%
27.	1985	Cook #2	MI	1,133.00	1,060.00	5,683,634	5,855.00	970.73	91.58%
28.	1985	Callaway #1	MO	1,236.00	1,120.00	8,045,764	7,884.90	1,020.40	91.11%
29.	1984	Zion #1	IL	1,098.00	1,040.00	5,692,090	6,030.40	943.90	90.76%
30.	1985	Zion #1	IL	1,098.00	1,040.00	4,813,949	5,107.40	942.54	90.63%
31.	1984	Dresden #2	IL	828.00	772.00	4,460,360	6,403.70	696.53	90.22%
32.	1986	Callaway #1	MO	1,236.00	1,120.00	7,199,113	7,124.50	1,010.47	90.22%
33.	1985	Lasalle #2	IL	1,078.00	1,036.00	3,430,898	3,699.90	927.29	89.51%
34.	1986	Dresden #2	IL	828.00	772.00	4,648,539	6,763.50	687.30	89.03%
35.	1985	La Crosse	WI	65.00	48.00	322,909	7,597.60	42.50	88.54%
36.	1983	Big Rock Pt. #1	MI	60.00	64.00	348,591	6,222.80	56.02	87.53%
37.	1984	Lasalle #2	IL	1,078.00	1,036.00	1,392,117	1,537.40	905.50	87.40%
38.	1986	Cook #1	MI	1,152.00	1,020.00	6,650,074	7,466.00	890.71	87.32%
39.	1986	Palisades	MI	812.00	730.00	841,244	1,324.40	635.19	87.01%
40.	1983	Dresden #2	IL	828.00	772.00	3,397,514	5,080.30	668.76	86.63%
41.	1986	Zion #1	IL	1,098.00	1,040.00	4,904,664	5,452.00	899.61	86.50%
42.	1984	Big Rock Pt. #1	MI	60.00	70.00	417,523	6,906.20	60.46	86.37%
43.	1985	Dresden #3	IL	828.00	773.00	4,390,064	6,621.30	663.02	85.77%
44.	1985	Dresden #2	IL	828.00	772.00	3,087,488	4,680.40	659.66	85.45%

TABLE 1 (Cont.)

Comparison of Cooper and Duane Arnold Utilization to Utilization of Nuclear Plants in States Adjacent to Iowa for 1983-1986.

Plant No.	Year	Plant Name	State	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
45.	1986	Lasalle #2	IL	1,078.00	1,036.00	5,717,014	6,534.50	874.90	84.45%
46.	1986	Bryon #1	IL	1,175.00	1,129.00	7,396,003	7,761.30	952.93	84.41%
47.	1983	Dresden #3	IL	828.00	773.00	4,147,939	6,403.10	647.80	83.80%
48.	1986	Lasalle #1	IL	1,078.00	1,036.00	2,018,117	2,331.90	865.44	83.54%
49.	1985	Zion #2	IL	1,098.00	1,040.00	5,114,186	5,901.30	866.62	83.33%
50.	1985	Cook #1	MI	1,152.00	1,020.00	2,116,062	2,491.10	849.45	83.28%
51.	1985	Lasalle #1	IL	1,078.00	1,036.00	4,809,395	5,584.90	861.14	83.12%
52.	1984	Lasalle #1	IL	1,078.00	1,036.00	5,206,209	6,055.00	859.82	82.99%
53.	1984	D.A.E.C.	*	597.15	515.00	2,717,563	6,405.00	424.29	82.39%
54.	1984	Dresden #3	IL	828.00	773.00	2,105,646	3,311.10	635.94	82.27%
55.	1983	D.A.E.C.	*	597.15	515.00	2,324,318	5,508.00	421.99	81.94%
56.	1986	La Crosse	WI	65.00	48.00	157,179	3,998.10	39.31	81.90%
57.	1985	Big Rock Pt. #1	MI	60.00	69.00	362,428	6,441.70	56.26	81.54%
58.	1986	D.A.E.C.	*	597.15	515.00	3,008,073	7,181.00	418.89	81.34%
59.	1986	Cooper	*	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
60.	1983	La Crosse	WI	65.00	48.00	201,267	5,232.60	38.46	80.13%
61.	1985	D.A.E.C.	*	597.15	515.00	1,940,485	4,712.00	411.82	79.96%
62.	1983	Cooper	*	836.00	764.00	3,343,199	5,546.00	602.81	78.90%
63.	1984	Cooper	*	836.00	764.00	3,469,953	5,902.00	587.93	76.95%
64.	1986	Dresden #3	IL	828.00	773.00	1,456,025	2,457.10	592.58	76.66%
65.	1986	Cook #2	MI	1,133.00	1,060.00	4,335,567	5,389.70	804.42	75.89%
66.	1985	Bryon #1	IL	1,175.00	1,129.00	1,012,898	1,192.40	849.46	75.24%
67.	1985	Cooper	*	836.00	764.00	1,067,748	1,885.00	566.44	74.14%
68.	1983	Point Beach #1	WI	524.00	495.00	2,384,844	6,499.20	366.94	74.13%
69.	1983	Zion #1	IL	1,098.00	1,040.00	4,016,176	5,742.20	699.41	67.25%
70.	1983	Lasalle #1	IL	1,078.00	1,036.00	1,639,809	3,085.90	531.39	51.29%
71.	1986	Fermi #2	MI	1,215.00	1,093.00	-23,926	437.70	-54.66	-5.00%
72.	1983	Bryon #1	IL	--	--	--	--	--	--
73.	1984	Bryon #1	IL	--	--	--	--	--	--
74.	1983	Callaway #1	MO	--	--	--	--	--	--
75.	1983	Fermi #2	MI	--	--	--	--	--	--
76.	1984	Fermi #2	MI	--	--	--	--	--	--
77.	1985	Fermi #2	MI	--	--	--	--	--	--
78.	1983	Lasalle #2	IL	--	--	--	--	--	--
79.	1983	Wolf Creek #1	KS	--	--	--	--	--	--
80.	1984	Wolf Creek #1	KS	--	--	--	--	--	--

Note: Information taken from The Licensed Operating Reactors Status Summary Report from the USNRC.

TABLE 2

1983-1986 Est. Average MW Generation and Utilization of Nuclear Plants Participating in Mapp

No.	Year	Plant Name	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MW) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
1.	1983	D.A.E.C.	597.15	515.00	2,324,318	5,508.00	421.99	81.94%
1.	1984	D.A.E.C.	597.15	515.00	2,717,563	6,405.00	424.29	82.39%
1.	1985	D.A.E.C.	597.15	515.00	1,940,485	4,712.00	411.82	79.96%
1.	1986	D.A.E.C.	597.15	515.00	3,008,073	7,181.00	418.89	81.34%
2.	1983	Quad Cities #1	828.30	769.00	5,776,352	8,261.00	699.23	90.93%
2.	1984	Quad Cities #1	828.30	769.00	3,349,735	4,687.00	714.69	92.94%
2.	1985	Quad Cities #1	828.30	769.00	6,072,319	8,244.00	736.57	95.78%
2.	1986	Quad Cities #1	828.30	769.00	4,420,669	5,880.00	751.81	97.77%
3.	1983	Quad Cities #2	828.30	769.00	3,151,307	5,622.00	560.53	72.89%
3.	1984	Quad Cities #2	828.30	769.00	4,983,925	6,840.00	728.64	94.75%
3.	1985	Quad Cities #2	828.30	769.00	4,556,866	6,248.00	729.33	94.84%
3.	1986	Quad Cities #2	828.30	769.00	4,722,778	6,401.50	737.76	95.94%
4.	1983	Cooper	836.00	764.00	3,343,199	5,546.00	602.81	78.90%
4.	1984	Cooper	836.00	764.00	3,469,953	5,902.00	587.93	76.95%
4.	1985	Cooper	836.00	764.00	1,067,748	1,885.00	566.44	74.14%
4.	1986	Cooper	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
5.	1983	Monticello	569.00	525.00	4,147,725	8,439.00	491.49	93.62%
5.	1984	Monticello	569.00	525.00	263,119	808.80	325.32	61.97%
5.	1985	Monticello	569.00	536.00	4,286,986	8,030.60	533.83	99.60%
5.	1986	Monticello	569.00	536.00	3,375,350	6,927.10	487.27	90.91%
6.	1983	Prairie Island #1	593.00	503.00	3,888,853	7,624.20	510.07	101.40%
6.	1984	Prairie Island #1	593.00	503.00	4,159,389	8,286.80	501.93	99.79%
6.	1985	Prairie Island #1	593.00	503.00	3,677,016	7,334.60	501.32	99.67%
6.	1986	Prairie Island #1	593.00	503.00	3,819,563	7,871.30	485.25	96.47%
7.	1983	Prairie Island #2	593.00	500.00	3,716,220	7,578.10	490.39	98.08%
7.	1984	Prairie Island #2	593.00	500.00	3,905,956	7,831.10	498.77	99.75%
7.	1985	Prairie Island #2	593.00	500.00	3,608,478	7,378.20	489.07	97.81%
7.	1986	Prairie Island #2	593.00	500.00	3,860,117	7,932.30	486.63	97.33%
8.	1983	Fort Calhoun #1	502.00	438.00	2,749,832	6,405.00	429.33	98.02%
8.	1984	Fort Calhoun #1	502.00	478.00	2,331,771	5,264.90	442.89	92.65%
8.	1985	Fort Calhoun #1	502.00	478.00	3,066,254	6,455.50	474.98	99.37%
8.	1986	Fort Calhoun #1	502.00	478.00	3,605,563	8,264.20	436.29	91.27%
9.	1983	Total MAPP	5,346.75	4,783.00	29,097,806	54,983.30		
9.	1984	Total MAPP	5,346.75	4,823.00	25,181,411	46,025.60		
9.	1985	Total MAPP	5,346.75	4,834.00	28,276,152	50,287.90		
9.	1986	Total MAPP	5,346.75	4,834.00	30,864,251	57,003.60		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from the USNRC.
Northwest Power Cooperative has Genoa #2 listed as a nuclear plant in the 1986 MAPP Load and Capacity Report, but Genoa was not listed in the The Licensed Operating Reactors Status Summary Report for 1983-1986.

TABLE 3

1986 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS – SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
1.	Calvert Cliffs #1	Maryland	918.00	825.00	5,830,738	6,856.40	850.41	103.08%
2.	Robinson #2	South Carolina	769.00	665.00	4,798,026	7,030.10	682.50	102.63%
3.	Kewaunee	Wisconsin	560.00	503.00	3,854,674	7,515.20	512.92	101.97%
4.	Calvert Cliffs #2	Maryland	911.00	825.00	7,006,666	8,408.70	833.26	101.00%
5.	St. Lucie #2	Florida	850.00	839.00	6,146,561	7,255.50	847.16	100.97%
6.	St. Lucie #1	Florida	890.00	839.00	7,052,031	8,353.60	844.19	100.62%
7.	Ginna	New York	517.00	470.00	3,610,266	7,659.90	471.32	100.28%
8.	Yankee-Rowe #1	Massachusetts	185.00	167.00	1,392,716	8,322.30	167.35	100.21%
9.	Maine Yankee	Maine	864.00	810.00	6,241,756	7,694.80	811.17	100.14%
10.	Three Mile Island #1	Pennsylvania	871.00	776.00	4,818,263	6,212.30	775.60	99.95%
11.	Point Beach #1	Wisconsin	524.00	485.00	3,770,070	7,787.60	484.11	99.82%
12.	Turkey Point #3	Florida	760.00	666.00	4,513,059	6,820.50	661.69	99.35%
13.	Palo Verde #2	Arizona	1,403.00	1,221.00	2,654,603	2,195.00	1,209.39	99.05%
14.	Arkansas #2	Arkansas	943.00	858.00	5,305,213	6,276.00	845.32	98.52%
15.	Millstone #1	Connecticut	662.00	654.00	5,247,940	8,176.20	641.86	98.14%
16.	Waterford #3	Louisiana	1,153.00	1,075.00	7,301,595	6,924.80	1,054.41	98.08%
17.	Point Beach #2	Wisconsin	524.00	485.00	3,417,550	7,188.30	475.43	98.03%
18.	Limerick #1	Pennsylvania	1,138.00	1,055.00	6,848,850	6,636.00	1,032.08	97.83%
19.	Prairie Island #2	Minnesota	593.00	500.00	3,860,117	7,932.30	486.63	97.33%
20.	Farley #2	Alabama	860.00	824.00	5,959,872	7,458.30	799.09	96.98%
21.	Summer #1	South Carolina	900.00	885.00	7,160,639	8,350.90	857.47	96.89%
22.	Prairie Island #1	Minnesota	593.00	503.00	3,819,563	7,871.30	485.25	96.47%
23.	Mcguire #2	North Carolina	1,305.00	1,150.00	6,209,772	5,604.60	1,107.98	96.35%
24.	Wolf Creek #1	Kansas	1,250.00	1,128.00	6,966,063	6,418.50	1,085.31	96.22%
25.	Farley #1	Alabama	860.00	825.00	5,726,616	7,216.80	793.51	96.18%
26.	Palo Verde #1	Arizona	1,403.00	1,221.00	5,851,048	4,988.80	1,172.84	96.06%
27.	Quad Cities #2	Illinois	828.00	769.00	4,722,778	6,401.50	737.76	95.94%
28.	Millstone #3	Connecticut	1,253.00	1,142.00	5,861,760	5,355.90	1,094.45	95.84%
29.	Zion #2	Illinois	1,098.00	1,040.00	7,334,233	7,372.00	994.88	95.66%
30.	Surry #1	Virginia	848.00	781.00	4,488,628	6,015.80	746.14	95.54%
31.	Fitzpatrick	New York	883.00	794.00	6,015,605	7,932.20	758.38	95.51%
32.	Vermont Yankee #1	Vermont	563.00	504.00	2,058,426	4,281.20	480.81	95.40%
33.	Quad Cities #1	Illinois	828.00	769.00	4,420,669	6,037.10	732.25	95.22%
34.	Beaver Valley #1	Pennsylvania	923.00	810.00	4,778,500	6,196.50	771.16	95.21%
35.	San Onofre #2	California	1,127.00	1,070.00	6,361,900	6,267.70	1,015.03	94.86%
36.	Surry #2	Virginia	848.00	781.00	4,498,941	6,075.00	740.57	94.82%
37.	Millstone #2	Connecticut	910.00	857.00	5,160,945	6,354.20	812.21	94.77%
38.	Oconee #1	South Carolina	934.00	860.00	4,784,795	5,872.60	814.77	94.74%
39.	Oconee #2	South Carolina	934.00	860.00	5,801,065	7,124.50	814.24	94.68%
40.	Trojan	Oregon	1,216.00	1,075.00	7,090,231	6,985.30	1,015.02	94.42%
41.	Susquehanna #1	Pennsylvania	1,152.00	1,032.00	5,830,291	5,995.20	972.49	94.23%
42.	Hatch #1	Georgia	850.00	750.00	3,645,387	5,164.40	705.87	94.12%
43.	North Anna #1	Virginia	947.00	915.00	6,310,739	7,330.90	860.84	94.08%
44.	Brunswick #1	North Carolina	867.00	790.00	5,973,813	8,069.90	740.26	93.70%
45.	Peach Bottom #2	Pennsylvania	1,152.00	1,051.00	6,896,565	7,014.00	983.26	93.55%
46.	Pilgrim #1	Massachusetts	678.00	670.00	1,027,531	1,646.00	624.26	93.17%
47.	Turkey Point #4	Florida	760.00	666.00	1,721,504	2,792.10	616.56	92.58%
48.	Salem #1	New Jersey	1,170.00	1,106.00	7,079,276	6,923.80	1,022.46	92.45%
49.	Susquehanna #2	Pennsylvania	1,152.00	1,032.00	5,448,219	5,734.20	950.13	92.07%
50.	Brunswick #2	North Carolina	867.00	790.00	2,911,036	4,029.60	722.41	91.44%
51.	Mcguire #1	North Carolina	1,305.00	1,150.00	5,164,769	4,916.00	1,050.60	91.36%
52.	North Anna #2	Virginia	947.00	915.00	6,022,050	7,210.50	835.18	91.28%
53.	Fort Calhoun #1	Nebraska	502.00	478.00	3,605,563	8,264.20	436.29	91.27%
54.	Indian Point #2	New York	1,013.00	849.00	3,810,597	4,926.80	773.44	91.10%
55.	Monticello	Minnesota	569.00	536.00	3,375,350	6,927.10	487.27	90.91%
56.	Oyster Creek #1	New Jersey	674.00	620.00	1,301,476	2,310.90	563.19	90.84%
57.	Oconee #3	South Carolina	934.00	860.00	6,064,306	7,782.80	779.19	90.60%
58.	Callaway #1	Missouri	1,236.00	1,120.00	7,199,113	7,124.50	1,010.47	90.22%

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 3 (Cont.)

1986 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS - SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
59.	Diablo Canyon #2	California	1,164.00	1,079.00	6,548,174	6,730.50	972.91	90.17%
60.	Nine Mile Point #1	New York	642.00	610.00	3,146,883	5,724.10	549.76	90.12%
61.	Dresden #2	Illinois	828.00	772.00	4,648,539	6,763.50	687.30	89.03%
62.	Salem #2	New Jersey	1,162.00	1,106.00	5,312,561	5,416.90	980.74	88.67%
63.	San Onofre #3	California	1,127.00	1,080.00	6,760,591	7,070.80	956.13	88.53%
64.	Crystal River #3	Florida	890.00	821.00	2,653,212	3,661.30	724.66	88.27%
65.	Catawba #1	South Carolina	1,305.00	1,145.00	5,182,492	5,155.00	1,005.33	87.80%
66.	Big Rock Point #1	Michigan	60.00	69.00	506,148	8,361.70	60.53	87.73%
67.	Cook #1	Michigan	1,152.00	1,020.00	6,650,074	7,466.00	890.71	87.32%
68.	Palisades	Michigan	812.00	730.00	841,244	1,324.40	635.19	87.01%
69.	Zion #1	Illinois	1,098.00	1,040.00	4,904,664	5,452.00	899.61	86.50%
70.	Indian Point #3	New York	1,013.00	1,000.00	5,525,581	6,432.40	859.02	85.90%
71.	Diablo Canyon #1	California	1,137.00	1,073.00	5,293,267	5,758.20	919.26	85.67%
72.	Catawba #2	South Carolina	1,305.00	1,145.00	1,297,202	1,325.80	978.43	85.45%
73.	Peach Bottom #3	Pennsylvania	1,152.00	1,035.00	4,849,352	5,545.30	874.50	84.49%
74.	Lasalle #2	Illinois	1,078.00	1,036.00	5,717,014	6,534.50	874.90	84.45%
75.	Bryon #1	Illinois	1,175.00	1,129.00	7,396,003	7,761.30	952.93	84.41%
76.	Lasalle #1	Illinois	1,078.00	1,036.00	2,018,117	2,331.90	865.44	83.54%
77.	La Crosse	Wisconsin	65.00	48.00	157,179	3,998.10	39.31	81.90%
78.	Duane Arnold	Iowa	597.00	515.00	3,008,073	7,181.10	418.89	81.34%
79.	Cooper Station	Nebraska	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
80.	Haddam Neck	Connecticut	600.00	569.00	2,132,316	4,698.90	453.79	79.75%
81.	Arkansas #1	Arkansas	903.00	836.00	3,573,159	5,447.70	655.90	78.46%
82.	Washington Nuc. #2	Washington	1,201.00	1,095.00	5,183,198	6,134.40	844.94	77.16%
83.	Hatch #2	Georgia	850.00	761.00	3,618,712	6,172.70	586.24	77.04%
84.	Dresden #3	Illinois	828.00	773.00	1,456,025	2,457.10	592.58	76.66%
85.	Cook #2	Michigan	1,133.00	1,060.00	4,335,567	5,389.70	804.42	75.89%
86.	River Bend #1	Louisiana	990.00	936.00	2,995,439	4,225.70	708.86	75.73%
87.	San Onofre #1	California	450.00	436.00	874,187	2,731.50	320.04	73.40%
88.	Grand Gulf #1	Mississippi	1,373.00	1,142.00	4,098,054	5,330.50	768.79	67.32%
89.	Hope Creek #1	New Jersey	1,118.00	1,067.00	1,030,793	1,679.00	613.93	57.54%
90.	Fort St. Vrain	Colorado	343.00	330.00	52,007	1,087.10	47.84	14.50%
91.	Davis-Besse #1	Ohio	962.00	860.00	3,486	116.60	29.90	3.48%
92.	Browns Ferry #1	Alabama	1,152.00	1,065.00	-36,374	0.00	0.00	0.00%
93.	Browns Ferry #2	Alabama	1,152.00	1,065.00	-47,061	0.00	0.00	0.00%
94.	Browns Ferry #3	Alabama	1,152.00	1,065.00	-41,625	0.00	0.00	0.00%
95.	Fermi #2	Michigan	1,215.00	1,093.00	-23,916	437.70	0.00	0.00%
96.	Rancho Seco #1	California	963.00	873.00	-32,157	0.00	0.00	0.00%
97.	Sequoyah #1	Tennessee	1,220.00	1,148.00	-40,178	0.00	0.00	0.00%
98.	Sequoyah #2	Tennessee	1,220.00	1,148.00	-64,434	0.00	0.00	0.00%
	Total		90,675.00	83,271.00	407,666,034	538,038.70		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 4

1987 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS – SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
1.	Calvert Cliffs #1	Maryland	918.00	825.00	5,268,477	6,237.00	844.71	102.39%
2.	Robinson #2	South Carolina	769.00	665.00	4,230,329	6,226.30	679.43	102.17%
3.	Three Mile Island #1	Pennsylvania	871.00	776.00	5,034,307	6,353.60	792.36	102.11%
4.	Kewaunee	Wisconsin	560.00	503.00	4,008,624	7,811.00	513.20	102.03%
5.	Prairie Island #2	Minnesota	593.00	500.00	4,429,989	8,760.00	505.71	101.14%
6.	Ginna	New York	517.00	470.00	3,797,701	7,994.00	475.07	101.08%
7.	Arkansas #2	Arkansas	943.00	858.00	6,605,168	7,681.70	859.86	100.22%
8.	Point Beach #1	Wisconsin	524.00	485.00	3,567,092	7,350.30	485.30	100.06%
9.	St. Lucie #1	Florida	890.00	839.00	5,715,344	6,814.10	838.75	99.97%
10.	Calvert Cliffs #2	Maryland	911.00	825.00	4,831,976	5,861.60	824.34	99.92%
11.	San Onofre #3	California	1,127.00	1,080.00	7,519,728	6,987.80	1,076.12	99.64%
12.	Point Beach #2	Wisconsin	524.00	485.00	3,606,145	7,481.10	482.03	99.39%
13.	Susquehanna #2	Pennsylvania	1,152.00	1,032.00	8,598,435	8,431.60	1,019.79	98.82%
14.	Prairie Island #1	Minnesota	593.00	503.00	3,590,268	7,234.20	496.29	98.67%
15.	St. Lucie #2	Florida	850.00	839.00	5,950,184	7,209.70	825.30	98.37%
16.	Millstone #2	Connecticut	910.00	857.00	6,892,531	8,180.10	842.60	98.32%
17.	Millstone #1	Connecticut	662.00	654.00	4,377,008	6,827.10	641.12	98.03%
18.	Fort Calhoun #1	Nebraska	502.00	478.00	3,060,620	6,531.70	468.58	98.03%
19.	Palo Verde #2	Arizona	1,403.00	1,221.00	8,190,044	6,858.20	1,194.20	97.80%
20.	Waterford #3	Louisiana	1,153.00	1,075.00	7,425,710	7,087.80	1,047.67	97.46%
21.	Oconee #3	South Carolina	934.00	860.00	5,084,967	6,069.90	837.73	97.41%
22.	Surry #1	Virginia	848.00	781.00	4,633,405	6,116.90	757.48	96.99%
23.	Vermont Yankee #1	Vermont	563.00	504.00	3,536,411	7,290.60	485.06	96.24%
24.	Hatch #1	Georgia	850.00	750.00	5,076,654	7,046.00	720.50	96.07%
25.	San Onofre #2	California	1,127.00	1,070.00	6,230,341	6,068.30	1,026.70	95.95%
26.	Wolf Creek #1	Kansas	1,250.00	1,128.00	6,504,145	6,013.00	1,081.68	95.89%
27.	Palo Verde #1	Arizona	1,403.00	1,221.00	5,268,268	4,504.50	1,169.56	95.79%
28.	Yankee-Rowe #1	Massachusetts	185.00	167.00	1,135,611	7,100.70	159.93	95.77%
29.	Indian Point #2	New York	1,013.00	849.00	5,146,333	6,333.00	812.62	95.72%
30.	Grand Gulf #1	Mississippi	1,373.00	1,142.00	7,726,991	7,100.00	1,088.31	95.30%
31.	Farley #1	Alabama	860.00	825.00	6,444,862	8,203.10	785.66	95.23%
32.	Mcguire #1	North Carolina	1,305.00	1,150.00	7,348,715	6,715.80	1,094.24	95.15%
33.	Surry #2	Virginia	848.00	781.00	4,790,953	6,457.90	741.87	94.99%
34.	Summer #1	South Carolina	900.00	885.00	5,151,897	6,136.90	839.50	94.86%
35.	Beaver Valley #1	Pennsylvania	923.00	810.00	5,620,890	7,322.90	767.58	94.76%
36.	Millstone #3	Connecticut	1,253.00	1,142.00	6,742,317	6,234.60	1,081.44	94.70%
37.	Mcguire #2	North Carolina	1,305.00	1,150.00	7,572,577	6,957.10	1,088.47	94.65%
38.	Haddam Neck	Connecticut	600.00	569.00	2,527,207	4,700.50	537.65	94.49%
39.	Quad Cities #1	Illinois	828.00	769.00	4,456,087	6,141.70	725.55	94.35%
40.	Quad Cities #2	Illinois	828.00	769.00	4,952,988	6,836.20	724.52	94.22%
41.	Catawba #1	South Carolina	1,305.00	1,145.00	6,377,839	5,928.60	1,075.77	93.95%
42.	Susquehanna #1	Pennsylvania	1,152.00	1,032.00	6,127,879	6,333.00	967.61	93.76%
43.	Monticello	Minnesota	569.00	536.00	3,533,357	7,052.90	500.98	93.47%
44.	Lasalle #2	Illinois	1,078.00	1,036.00	4,542,494	4,700.20	966.45	93.29%
45.	Nine Mile Point #1	New York	642.00	610.00	4,615,169	8,130.50	567.64	93.06%
46.	Farley #2	Alabama	860.00	824.00	4,902,626	6,397.80	766.30	93.00%
47.	Diablo Canyon #1	California	1,137.00	1,073.00	8,284,201	8,342.80	992.98	92.54%
48.	Oyster Creek #1	New Jersey	674.00	620.00	3,110,919	5,422.90	573.66	92.53%
49.	Vogtle #1	Georgia	1,157.00	1,084.00	3,921,520	3,920.40	1,000.29	92.28%
50.	Maine Yankee	Maine	864.00	810.00	4,042,901	5,415.40	746.56	92.17%
51.	Diablo Canyon #2	California	1,164.00	1,079.00	5,715,218	5,754.50	993.17	92.05%
52.	Callaway #1	Missouri	1,236.00	1,120.00	6,321,776	6,143.90	1,028.95	91.87%
53.	Turkey Point #4	Florida	760.00	666.00	2,636,070	4,318.90	610.36	91.65%
54.	Hope Creek #1	New Jersey	1,118.00	1,067.00	7,277,090	7,457.10	975.86	91.46%
55.	Zion #2	Illinois	1,098.00	1,040.00	5,114,145	5,384.50	949.79	91.33%
56.	North Anna #2	Virginia	947.00	915.00	5,653,448	6,785.50	833.17	91.06%
57.	Harris #1	North Carolina	950.00	860.00	3,378,829	4,323.60	781.49	90.87%
58.	River Bend #1	Louisiana	990.00	936.00	4,964,440	5,837.70	850.41	90.86%
59.	Brunswick #1	North Carolina	867.00	790.00	4,046,631	5,652.30	715.93	90.62%

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 4 (Cont.)

1987 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS – SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
60.	Palisades	Michigan	812.00	730.00	2,634,430	3,983.10	661.40	90.60%
61.	Hatch #2	Georgia	850.00	761.00	5,755,607	8,390.40	685.98	90.14%
62.	Zion #1	Illinois	1,098.00	1,040.00	6,058,385	6,482.40	934.59	89.86%
63.	Indian Point #3	New York	1,013.00	1,000.00	4,850,586	5,399.90	898.27	89.83%
64.	Fitzpatrick	New York	883.00	794.00	4,198,340	5,894.80	712.21	89.70%
65.	Duane Arnold	Iowa	597.00	515.00	2,540,837	5,514.80	460.73	89.46%
66.	Catawba #2	South Carolina	1,305.00	1,145.00	7,169,495	7,019.00	1,021.44	89.21%
67.	Perry #1	Ohio	1,250.00	1,205.00	828,484	773.40	1,071.22	88.90%
68.	Big Rock Point #1	Michigan	60.00	69.00	374,931	6,132.20	61.14	88.61%
69.	Salem #1	New Jersey	1,170.00	1,106.00	6,211,441	6,363.20	976.15	88.26%
70.	Salem #2	New Jersey	1,162.00	1,106.00	6,172,052	6,343.40	972.99	87.97%
71.	Brunswick #2	North Carolina	867.00	790.00	5,694,104	8,205.80	693.91	87.84%
72.	Beaver Valley #2	Pennsylvania	923.00	885.00	738,104	949.80	777.12	87.81%
73.	Oconee #1	South Carolina	934.00	860.00	5,028,061	6,694.70	751.05	87.33%
74.	Trojan	Oregon	1,216.00	1,075.00	4,347,772	4,631.60	938.72	87.32%
75.	Cooper Station	Nebraska	836.00	764.00	5,522,126	8,292.40	665.93	87.16%
76.	Dresden #3	Illinois	828.00	773.00	4,395,502	6,595.70	666.42	86.21%
77.	North Anna #1	Virginia	947.00	915.00	3,568,907	4,525.50	788.62	86.19%
78.	Peach Bottom #2	Pennsylvania	1,152.00	1,051.00	1,552,256	1,724.00	900.38	85.67%
79.	Limerick #1	Pennsylvania	1,138.00	1,055.00	5,318,987	5,926.70	897.46	85.07%
80.	Peach Bottom #3	Pennsylvania	1,152.00	1,035.00	1,460,062	1,659.60	879.77	85.00%
81.	San Onofre #1	California	450.00	436.00	2,708,001	7,323.40	369.77	84.81%
82.	Oconee #2	South Carolina	934.00	860.00	6,228,692	8,567.10	727.05	84.54%
83.	Crystal River #3	Florida	890.00	821.00	3,620,784	5,263.80	687.87	83.78%
84.	Cook #1	Michigan	1,152.00	1,020.00	5,033,767	5,918.80	850.47	83.38%
85.	Washington Nuc. #2	Washington	1,201.00	1,095.00	5,397,981	5,981.00	902.52	82.42%
86.	Turkey Point #3	Florida	760.00	666.00	856,146	1,567.70	546.12	82.00%
87.	Clinton #1	Illinois	NA	933.00	684,103	898.30	761.55	81.62%
88.	Dresden #2	Illinois	828.00	772.00	3,342,347	5,345.30	625.29	81.00%
89.	Davis-Besse #1	Ohio	962.00	860.00	5,063,984	7,312.40	692.52	80.53%
90.	Bryon #1	Illinois	1,175.00	1,129.00	5,330,576	6,007.30	887.35	78.60%
91.	Bryon #2	Illinois	1,175.00	1,120.00	1,970,901	2,280.40	864.28	77.17%
92.	Cook #2	Michigan	1,133.00	1,060.00	5,026,564	6,251.60	804.04	75.85%
93.	Arkansas #1	Arkansas	903.00	836.00	4,763,342	7,723.10	616.77	73.78%
94.	Lasalle #1	Illinois	1,078.00	1,036.00	4,073,067	5,456.80	746.42	72.05%
95.	Braidwood #1	Illinois	NA	1,120.00	1,456,651	2,610.70	557.95	49.82%
96.	Palo Verde #3	Arizona	1,403.00	1,221.00	319,661	620.70	515.00	42.18%
97.	Fermi #2	Michigan	1,215.00	1,093.00	1,392,801	4,084.20	341.02	31.20%
98.	Fort St. Vrain	Colorado	343.00	330.00	180,922	2,030.40	89.11	27.00%
99.	Nine Mile Point #2	New York	1,214.00	1,080.00	260,995	1,059.00	246.45	22.82%
100.	Browns Ferry #1	Alabama	1,152.00	1,065.00	-12,718	0.00	0.00	0.00%
101.	Browns Ferry #2	Alabama	1,152.00	1,065.00	-34,470	0.00	0.00	0.00%
102.	Browns Ferry #3	Alabama	1,152.00	1,065.00	-50,980	0.00	0.00	0.00%
103.	Pilgrim #1	Massachusetts	678.00	670.00	0	0.00	0.00	0.00%
104.	Rancho Seco #1	California	963.00	873.00	-56,759	0.00	0.00	0.00%
105.	Sequoyah #1	Tennessee	1,220.00	1,148.00	-48,236	0.00	0.00	0.00%
106.	Sequoyah #2	Tennessee	1,220.00	1,148.00	-59,378	0.00	0.00	0.00%
	Total		98,682.00	92,731.00	449,087,064	584,375.40		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

END NOTES

[1] Tables 1 and 2 are drawn from a report authored by Shari Cameron of Utilities Division, Department of Commerce, State of Iowa. A full reference appears in the Bibliography. Tables 3 and 4 were prepared by Leighann O'Tool of the Utilities Division, Department of Commerce, State of Iowa.

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Bubble Memory Technology: Its Impact on Metering and Rate Structure

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Bubble memory will replace magnetic tape as the principal means of implementing product differentiation and rate structures within the electric utility industry for two reasons: first, research and commercial development of bubble memory technology is moving forward after the technology was abandoned by several U.S. producers. Advances in the technology will reduce the importance of silicon and increase the importance of ferrous magnetic substances by achieving very high density rates of bit storage, which in turn will bring economies of scale and rapidly declining average costs for the storage of information. Second, bubble memory's performance already exceeds that of magnetic tape, and the difference between these levels of performance will become even greater.

The remainder of this discussion is divided into three parts: the first is a brief explanation of how product differentiation in the electric utility industry creates a need for efficient information storage; the second is a comparison of magnetic tape and bubble memories; and the third section explains why bubble memory technology is viable, marketable, and dependable.

I

In the context of an electric utility, product differentiation means that electric power sales represent several different services that are distinguished from one another by such criteria as the time of the sale, the customer making the purchase, whether the sale is short-term, long-term, intermittent, or continuous, and any other criteria that would be relevant. Product differentiation naturally entails different prices for different commodities. For example, electric power subject to interruption is clearly a different commodity than power not subject to interruption; similarly, electric power sold at the time of the system's peak demand is different from power sold at another time.

A utility that charges for its product on a time-of-day basis has to know the moment-by-moment purchases of a customer; such information becomes voluminous in a matter of hours and must be processed, evaluated, and stored. Since charging for power sales on a time-of-day basis is now a regular feature of many utilities' rate structure, and since interruptable and standby power sales are becoming more common both to industrial customers and to other utilities, even more information (and storage) will be required. These needs will rapidly exceed the capabilities of magnetic tape as a sales recording device.

II

Bubble memory is a storage medium in solid state form, in which the presence or absence of a "bubble" in a submicroscopic magnetic domain on a chip represents respectively a 0 or a 1, so that data can be stored in binary form. Unlike other kinds of memory, bubble memory has no moving parts and is nonvolatile (i.e., not power-dependent): it retains recorded data even if the power supply is interrupted. [1] Although magnetic tape also retains data when the power supply is interrupted, measurement of consumption using magnetic tape entails a mechanical system installed and reset manually, the shortcomings of which make possible inaccurate measurement of consumption and concomitantly lower revenue. This is readily demonstrated by an examination of the steps required for magnetic tape to measure power consumption by an industrial customer on a time-of-day rate.

The tape of a magnetic tape meter is usually divided into two or more tracks: one track always records time pulses sent from an external clock, while the other tracks record data pulses that represent power consumption. The time pulses are recorded according to a predetermined interval length. Consumption within a time period is determined by adding up the number of data pulses recorded between two adjacent time pulses. Once an initial start time is determined, all time pulses will occur at those regular intervals that subdivide the billing period. For example, if the start time is 9:00 and the interval length is 15 minutes, the time pulses occur at 9:15, 9:30, 9:45, and so on.

While this may seem simple to implement theoretically, practically it poses several problems. Magnetic tape metering requires extensive training of the personnel that install, maintain, and remove the tapes from the metering site. A tape metering system is essentially a mechanical system insofar as it relies on the tape drive gears to operate properly and move the tape at the required number of inches per second; otherwise the space between adjacent time pulses may not represent the time interval specified by the utility. Referring to the example above, the interval could represent 9:03 to 9:12, or 9:03 to 9:20 depending on the speed of the tape drive.

The metering tapes also have nonmagnetic leaders and trailers which record nothing [2] so that when the tape begins, it must be positioned properly for the initial time and data pulses to fall on the magnetic portion. Otherwise there is a mismatch between tape start time and recorded information, causing a loss of information, and in metering situations, loss of information usually means loss of revenues.

There is another possibility for error. The tape must be replaced before the magnetic trailer is reached, or billing information is lost at this stage, too. This means that the tape must be physically replaced: therefore, the utility must follow a precise schedule not only to read the tapes but to replace them as well.

There are other problems. The initial start time of the first interval on the tape must be set from an external clock, one that runs independently of the tape. The interval length can only be changed by changing the external clock. While this is not a problem for a single meter, it would be a very expensive problem, in terms of labor costs, where several hundred meters are involved. So once a utility selects an interval's starting point and its length, change is a problem.

All of these points underscore the importance of trained personnel in maintaining, setting, and reading the meters. But this also highlights the vulnerability of billing in the event of a labor strike.

Performance characteristics are particularly important in metering situations because the storage medium is subject to the extremes of weather: heat, cold, humidity, and dust. How does magnetic tape hold up compared with bubble memory under these conditions?

Magnetic tape expands with heat and contracts with cold, ages, wrinkles, and develops ripples. The recording head is subject to oxide buildup and must be regularly cleaned [3] Any of these can cause data loss or data error, so that the tape is incorrectly read and translated to a mainframe computer. Bubble memories produced by Intel Magnetics can operate within a range of 0 to 70 Celsius [4] the limits of the range will expand to -20 and 85 Celsius in the very near future [5] Bubble memory is minimally affected by dust, vapor,vibration [6] and hard radiation [7] even in very harsh environments, it maintains data integrity.

Furthermore, the reliability of bubble memory is a distinct advantage to a utility's metering capability. The failure rate for a 128K bubble memory device is 1 in 10 to the 15th power; this is about once in every 100 years of operation [8] The mean repair time (i.e., for replacement) of a bubble memory unit is only a few minutes [9] The reliability of a magnetic tape system is far less simply because it is a mechanical system [10] a major portion of any magnetic tape storage system involves mechanically operated systems-control and -drive hardware.

Another point of comparison is storage capacity, and magnetic tape used in metering situations has a maximum capacity of 3 M bits square inch [11] in 1983. Intel Magnetics introduced a 4M bit chip measuring 1.46 x 1.35 centimeters with a storage capacity of slightly more than 2 M bits per square centimeter or 5 M bits per square inch [12] On this basis, bubble memory has a 60capability of magnetic tape does not apply in metering situations because increasing data storage on tape at a metering site requires decreasing the speed at which the tape moves and because there is a limit to how slow a tape can be set to move [13] For example, for data collected on a 15-minute interval basis, tapes used in metering situations have a practical storage limit of 90 days. Bubble memory, on the other hand, has no moving parts: its full storage capacity can always be utilized as this capacity continues to increase with technological advances. Bubble memory already has a capacity in the range of 6 months for 15-minute intervals and 2 months for 5-minute intervals. Unlike magnetic tape, bubble memory technology offers the possibility of remote readings over telephone lines or other data transmission paths. Telephone interrogation of magnetic tapes is not practical. Remote data access and bubble memory technology also offer the possibility of automatic reprogramming from a central source of all interval lengths and start times for all meters simultaneously.

The foregoing clearly implies that the use of bubble memory would be substitution of capital for labor, thereby providing greater management control over the entire process. More important, however, is the flexibility (that does not now exist) in a utility's rate structure that bubble memory can provide. Consider the following as a case in point. For billing purposes, the practical minimum interval length on a magnetic tape is 15 minutes. This interval length cannot accurately measure power used in time periods that are shorter than the interval and that overlap interval boundaries.

For example, given the 15-minute interval beginning at 9:00, there is no way to measure the power flow from 9:07 to 9:22, and this is particularly important where large inductive loads operate intermittently and where the operation of these loads is timed to circumvent the real measure of the power flow: for example, if an electric drag line or an electric furnace is used between 9:07 and 9:22, the power flow measure on a magnetic tape meter with 15-minute intervals described above would only capture half the actual power flow. In this situation, the unmeasured power sales become system-demand losses to the utility. These losses usually range from 5 percent to 10 percent of a utility's net generation.

However, a bubble memory using a one-minute or five-minute interval would solve this problem by recording a higher sales volume, leading to lower system-demand losses and to either greater revenue for a given sales price or lower prices because of a given revenue requirement. This could have a substantial industry-wide effect by bringing in several hundred millions of dollars that are otherwise lost or by keeping electrical price levels lower. Furthermore, bubble memory's capability to record power usage accurately no matter how short the duration will also provide for more precise cost-of-service studies, enhance the utility's ability to sell interruptible power, and thereby more fully utilize spinning reserve. The last point of comparison to be made here between bubble memory and magnetic tape is data access. At one time, both magnetic tape and bubble memory entailed sequential access to data: the only way to access data in the middle of stored information was by accessing all information leading up to what was desired. Improvements in chip architecture for bubble memories now make data access time two to four times faster than either hard or floppy disk drive access times [14] Of course, data access time on a magnetic tape cannot be improved by manipulating the medium, and this further demonstrates that bubble memory storage is superior to tape storage

III

Major factors in adopting any new technology are expected life and serviceability. Bubble memory is not new, but it is still a fairly recent development. The driving force behind the discovery of magnetic bubbles was a group of scientists at Bell Laboratories, prominent among them A.H. Bobeck, U.F. Gianola, R.C. Sherwood, H.E.D. Scovil, and W. Shockley [15] Theoretical discoveries in the late 1960's by the Bell group gave impetus to further research and attempts at commercial development throughout the 1970's. Research has been conducted along several lines of development: materials analysis, chip architecture, and chip fabrication, to mention a few. At one time in the late 1970's, development programs were underway at Texas Instruments, National Semiconductor, Rockwell International, Motorola, Intel, and Signetics. Bell Labs developed an experimental 11.5 M bit bubble device only 1.3 inches square; even Hewlett Packard developed applications in desktop calculators [16] All of this is sufficient indication that the bubble memory market was perceived as one that would grow and be viable. In the late seventies, there was a consensus that the annual sales volume in the United States would approach 1 billion dollars and that the technology would cost only 10 millicents per bit [17] but by 1981 Intel was the only domestic producer of bubble memory: all the others had abandoned the market.

Far from being sidelined in terms of research and development, bubble memory remains viable because it is ideally suited for portable applications and because of its radiation- hardness. For example, in the mid-1970's it was considered for inclusion as a component for an on-board attitude control computer for spacecraft [18] Research on magnetic bubbles continues in Japan, Britain, France, West Germany, and the Soviet Union. From the standpoint of development, in the United States, Intel negotiated a "second source" agreement with Motorola in 1982, so that technological research, product development and manufacture of bubble memory will be shared between the two firms [19] This is significant because bubble memory will have a full line of support electronics, the lack of which had previously hampered commercial development. Furthermore, research done by IBM at San Jose determined that "magnetic bubble memories must have a capacity of at least 4 M bits to challenge RAM devices on the basis of cost." [20] It is no coincidence, therefore, that Intel introduced a 4 M bit chip in 1983. This is a clear signal that further commercial development of bubble memory is anticipated: A 16 M bit device is the next logical step [21] and it could be available by the early 1990's. Research is under way at Hitachi, Fujitsu, Sagem [22] IBM, and Bell Labs [23] It must not be forgotten that the original corporate developer of the bubble memory, Bell Labs and its parent AT&T, were prevented from entering the computer technology market. But this has all changed with the recent divestiture of AT&T. It is only logical to conclude that the founder of the technology would seek to commercialize and expand it now that legal restrictions are removed from commercial competition in the industry.

Further development of the technology can be expected because of the tremendous potential for miniaturization and scale economies in bubble fabrication. In fact, scale economies are already occuring. In 1979 Intel published a series of guaranteed prices for bubble devices purchased in quantities of 25,000. The

prices of devices were $1000 in 1980, $600 in 1981, and $300 in August of 1982. By January of 1983, the prices fell below $250 in lots of 10,000 [24] The price of the 4 M bit device is expected to approach $150 by 1986 [25] Achieving low-cost chips requires high device density and large chip capacity. The complementary technologies to achieve this are either in place or undergoing advancement themselves. For example, the Intel 4 M chip referred to earlier in this essay was fabricated using x-ray lithography [26] this is the production tool that enabled the achievement of 4 M bit density, but as time and research continue, x-ray lithography can be expected to give way to electron beam lithograpny [27] the ultimate key to bubble miniaturization and scale economies.

The ongoing research and commercial development makes a myth of the notion that bubble memory is a dead technology. The complexities of the utility industry are already outdistancing the capabilities of the magnetic tape, and new avenues must be investigated. Bubble memory is a viable and superior option to develop for the long term.

Conclusion

Some of the technological differences between magnetic tape and magnetic bubble memory have been discussed and policy implications briefly outlined. The industry cannot ignore the technological changes that are coming in the 1980's and 1990's. The limitations of magnetic tape necessitate a vigorous search for a suitable substitute, one that does not allow data error/loss in metering, one that can measure interruptible and standby power and insure against revenue erosion by means of interval adjustment, one that allows for remote monitoring using data communications technology, and one that makes for greater flexibility in the development of rate structures.

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25. "Memory Chip Stores 4 Megabits." High Technology, Vol. 3 No. 2 (February, 1983), p. 67.

26. Ibid.

27. Chang, op. cit., p. 60.

The Sine Qua Non of Order 636: Cooperative Competition, Information Flow, and Rate Design

Stephen N. Brown

The FERC completed a remarkable turnaround in regulatory philosophy in its gas pipeline restructuring order.

Competition for natural gas supply will promote the nation's economic growth. That idea describes the essence of Federal Energy Regulatory Commission (FERC) Order No. 636 and provides the driving force behind the commission's effort to restructure the natural gas industry. But the FERC's eventual success ultimately depends on the spirit of "cooperative competition": The willingness of individual players to share information about day-to-day pipeline operations and the vital conditions that determine rate design and prices.

The FERC itself is acutely aware of this vulnerability. That is why the commission framed Order 636 with language that simultaneously coaxes, cajoles, and urges the industry to do its patriotic duty (see box).

This language makes FERC's order 636 truly remarkable. It tells the pipelines that their traditional way of doing business blocks the spread of competition within the natural gas industry. This finding was unthinkable twenty years ago. The natural gas industry was built on the principle of bundled, city-gate, firm sales service. During the industry's early years, certificates of convenience and necessity were issued to pipelines only if they offered such service to distribution companies. The industry's building block is now an unlawful restraint of trade.

The pipelines' old virtue is now a vice because the merchant function is gradually fading away. In the first quarter of 1984 pipeline sales made up 94 percent of throughput. By the second quarter of 1991 pipeline sales totaled only 12 percent of throughput. Nevertheless, in 1991 pipeline sales consumed over 60 percent of peak-day capacity. This surprising mismatch between throughput and capacity told the FERC that pipeline sales enjoy a clear advantage over the open-access firm transportation of nonpipeline natural gas:

Free-flowing Information

The FERC intends to solve the fairness problem by establishing equivalency between bundled, city-gate firm sales by the pipeline and open-access firm transportation of nonpipeline natural gas. The solution lies with the idea of "No-Notice Transportation Service." Success will depend on cooperation between the various segments of the industry, as the FERC is quite aware:

> [We] expect the pipelines and all interested participants to craft . . . the operating conditions needed to

The Spirit of 636

Drawing on Patriotism:

"[We] . . . remind the industry that it is in the nation's best interest and the industry's interest . . . to keep gas flowing and deliverable when and where needed and . . . not unreasonably inhibit the meeting of gas purchasers and gas sellers in a competitive market." [Order No. 636, p. 96.]

From Virtue to Vice:

"[The] pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry . . . this harm has an unreasonable impact on gas sellers and is an unlawful restraint of trade." [Order No. 636, p. 39.]

To Level the Field:

"Pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors." [Order No. 636, p. 32.]

An Open Book, But Who Will Read It?

Pipelines In a Fishbowl:

Pipelines will retain operational control, but will perform in a fishbowl, since all buyers and sellers must now constantly monitor pipeline operations.

Second-guessing by Customers:

Buyers and sellers are likely to develop "shadow" operations groups that not only will monitor operating conditions, but are also likely to second-guess the pipelines from time to time.

Information Overload:

A tremendous need will arise for accurate, speedy, and voluminous information on storage facilities, receipt and delivery points, pressure, pumping stations, capacity reallocations, and anything else that might be viewed as relevant.

> ensure that the pipelines can provide a "no-notice" transportation service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlement on a daily basis without incurring daily balancing and scheduling penalties.

To its lasting credit, the FERC recognizes that "no-notice" markets will not be fully competitive without another simultaneous development — the rapid and free flow of information. The FERC clearly says "that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations." This policy will work only if all players cooperate. Any effort to tilt the scales by withholding or disguising relevant information may easily subvert the FERC's goal of uniting gas purchasers and gas sellers in a competitive market place. The importance of good and timely information cannot be overestimated for a competitive market, whether it's the New York Stock Exchange, the Chicago Board of Trade, or the natural gas industry.

The FERC's policy on information flow has major implications. The pipelines may not yet have realized that the order lays out their operations for all to see. It's just like letting one person cut the cake while others choose which piece they want. For example, the pipelines must make electronic bulletin boards accessible to all users and no one will be granted preferential access to the boards:

> The pipelines must keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records . . . pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information.

The FERC is right to be cautious, considering the impending modernization of the nation's telecommunications infrastructure and uncertain behavior of the players in the natural gas industry. How will the new infrastructure affect the competitiveness of the natural gas industry? Will the pipelines really want to give up their advantage of occupying 60 percent of the peak-day capacity, particularly when their sales are less than 20 percent of annual throughput? Do local distribution companies (LDCs) really want to jump into a competitive market with complexities that rival those of a major stock exchange? Will the upstream and downstream pipelines really cooperate with one another?

Rate Design

The restructuring hearings will not deal with the single biggest rate design issue for pipelines: transportation cost recovery through the "straight fixed-variable method" (SFV). This rate design definitely affects the central feature of the FERC's restructuring proposal: The presumed willingness of gas buyers to participate in "no-notice transportation service."

The SFV method removes all fixed costs from the pipeline's commodity charge for transporting gas. For years the FERC allowed significant amounts of fixed costs in the pipeline's commodity charge. The commission now believes such practice inhibits competition by preventing gas purchasers from making accurate comparisons of prices, terms, and conditions offered by various gas sellers. The SFV method corrects this mistake and promotes "head-to-head, gas-on-gas competition."

The FERC prefers the SFV rate design but suggests that it may be avoided by any particular pipeline if the parties agree on an alternative costing method. If the parties can't persuade the FERC to deviate from its preference, or if they lack a consensus on rate design, the SFV method will prevail. The odds favor SFV, since rate design is rarely characterized by harmony. It's an impossible goal because the customers' load factors are too diverse. In fact, the SFV method reduces costs for customers with high annual load factors, and increases costs for customers with poor load factors. This explains both the support and the opposition to SFV — with a rate design consensus unlikely, there will be no viable alternative.

The SFV method will increase costs for some customer groups. The FERC has agreed to limit such increases to 10 percent and to phase in the increase over a four-period after the pipeline's initial compliance filing. But after four years, the phase-in terminates and the limitations expire for SFV-related cost increases. After that customers are on their own; they must adapt to changed circumstances. The burden cannot be laid at the door of producers or pipelines. It falls exclusively on gas consumers and perhaps their agents acting as gas purchasers.

What does this mean for hot new designer rates? It means that "no-notice" transportation rates must strongly reflect the prevailing operating conditions on the pipeline.

I'm not advocating a different price for every hour of the year on every different section of the line. But I am advocating that the industry get far away from the idea that "one rate fits all." The nature of a competitive market place allows for some tailoring and customizing of individual prices and contract terms. Indeed, if the market doesn't exhibit these characteristics at all, then it's not really a competitive market. Customizing may be one way to develop a "no-notice" competitive transportation market. There's certainly room for this market considering that interruptible transportation now accounts for 51 percent of pipeline deliveries to market.

Tailored rate designs ought to reflect a match between the customers needs, the producer's supply, and the pipeline's operating conditions. This brings me back to my emphasis on the need for good information. More than ever before, there will be an emphasis on the optimal scheduling of pipeline flows, storage, maintenance, controlling, and shifting consumer demand. In this situation command and control of information is paramount because a competitive market inevitably reduces profit margins for the poorly organized and inefficient party. To be effective negotiators, gas purchasers and sellers must have the ability to recognize and act on the opportunities offered by the ebb and flow of a pipeline's operating conditions. FERC clearly understands this and accordingly has decided to make pipeline operations an open book for both gas buyers and sellers.

I hope LDCs and their customers are ready for the responsibilities of a competitive natural gas market. The LDCs fit the national pattern already noted by the FERC: Buying a lot of gas on the spot market, using interruptible transportation, and relying on pipeline sales for peak-day purchases, while keeping overall bills below the potential cost of exclusive reliance on pipeline gas. The LDCs have had an extended learning opportunity. It's up to them to take this experience and skillfully apply it the emerging market that the FERC is now creating.

The competitive market certainly raises uncertainties at the federal and state levels. How will the FERC draw the boundary between proprietary information and information required to make the market competitive? How does state regulation establish risk-sharing between the core customers and an LDC making a gas purchase on their behalf? Will a purchased gas adjustment (PGA) clause continue to serve a useful purpose once pipelines comply with Order 636?

These questions don't exhaust the possibilities, but sooner or later, perhaps in a rate case setting or in a notice of inquiry, the LDCs will have to show their state regulatory body that they've read the open book on pipeline operations and made good use of it. This would serve everyone's interest, and the LDCs should avoid putting truth to old sayings: "You can lead a horse to water but you can't make it drink," or, in the case of pipeline operations, "seeing a book open does not make its reader think."

Order 636-A: A Short-term Solution?

On July 30 the FERC met and voted to approve Order No. 636-A, in which it slightly relaxed its effort to push the natural gas industry into the information age. Pipeline capacity released for less than one calendar month will now require neither advanced posting on electronic bulletin boards nor bidding.

But the practicality of omitting short-term transactions from posting and bidding requirements will diminish as the industry learns better how to handle transactions of various sizes and duration. These short-term events cause a nuisance only when the players in the market are not ready to use or interpret the information that they provide. Any competitive market features short-term, low-volume transactions, and there is no inherent reason why such transactions should hinder a competitive market in its allocative efficiency. Thus, we can likely expect that the FERC will eventually withdraw Order 636-A and replace it in a subsequent rule making.

Competition Versus Reliability

The importance of pipeline operations cannot be overstated because major changes in public policy towards regulated industry are constrained by technical considerations. The FERC's restructuring efforts are no exception. At the inception of the "Mega-NOPR," pipeline system reliability was incompatible with competition — one condition precluded the other. With the industry's help, the FERC resolved this apparent contradiction and found that system reliability and competition coexist. Neither one preempts the other.

With a little imagination, the FERC might apply this reasoning to the issue of transmission access in the electric power industry. All that's needed is to substitute "electric utility" for "pipeline" and "no-notice transmission" for "no-notice transportation". Can the FERC make competition in the electric industry compatible with system reliability? Perhaps not, but the electric industry may soon be hard pressed to explain why system reliability and competition cannot coexist in the power industry.

The FERC has offered a number of individual steps that, if taken quickly and cooperatively, will speed the gas industry's adoption of competitive market practices. But I emphasize the *fragility* of the FERC's proposal and the need for cooperation to make the system work. Hot new designer rates won't sell in the market place if the players torpedo the restructuring. I agree with the unspoken sentiment expressed by the FERC: Restructuring the industry will work only if the players adopt the spirit of "cooperative competition." That should characterize all bargaining between sellers, buyers, and pipelines.

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