COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY UTILITIES CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	) CASE NO. 2002-00224
AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF LOUISVILLE GAS & ELECTRIC CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	) CASE NO. 2002-00225

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2002

002783

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY UTILITIES CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	**)) CASE NO. 2002-00224)**
AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF LOUISVILLE GAS & ELECTRIC CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	**)) CASE NO. 2002-00225)**

DIRECT TESTIMONY OF LANE KOLLEN

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for nearly twenty-five years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. I have testified before the

Kentucky Public Service Commission on numerous occasions, including recent Louisville Gas and Electric ("LGE") and Kentucky Utilities Company ("KU") base ratemaking and alternative rate plan proceedings, as well as the proceeding involving the merger of the two Companies. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group a large users taking electric service on the LGE and KU systems.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the differences between the line loss factor incorporated in the MISO tariff and the line loss factor applied to LGE and KU off-system sales for fuel adjustment clause ("FAC") purposes, and to recommend a process that would enable the Commission to investigate and determine the correct quantification of line losses for FAC purposes with the assistance of an independent transmission planning expert.

Q. Please summarize your testimony.

A. LG&E and KU began providing and taking transmission service for all load, retail and off-system, pursuant to the MISO OATT in February 2002. The MISO tariff incorporates a 2.221% line loss factor for the LG&E Energy ("LGEE") control area, which applies equally to all transmission load, both retail and off-system. For FAC purposes, the Commission currently utilizes a 1% loss factor for off-system sales and implicitly requires the retail load to carry all actual transmission line losses other than the 1% assigned to off-system sales.[1]

The MISO 2.221% loss factor was based upon a comprehensive study of the LGEE control area and other MISO control areas. The MISO loss factor incorporated in the MISO study reflects "average" line losses over a variety of load conditions during the study year. It appears that the MISO study quantified the fixed losses at an average level of 0.183% and the variable losses at an average level of 2.038%. The MISO loss factor is applied to both retail and off-system loads.

The 1% loss factor currently utilized in the LGE and KU FAC filings is based upon a study performed by a consultant on behalf of LGE and KU for the LGE control area

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[1] A portion of KU's fuel costs and line losses are also collected from its all requirements wholesale

only, and is referred to by LGE and KU as the "Normand" study. The most recent report summarizing the Normand study concluded that there were "incremental" or variable line losses of 0.636% to 0.750% associated with off-system sales. Methodologically, the Normand study assigned 100% of the fixed losses in the LGEE control area to retail ratepayers and none to the off-system sales.

Thus, there appears to be a disconnect between the line loss costs incurred by LGE and KU pursuant to the MISO tariff and the allocation of line loss costs between retail and off-system sales in the Companies' FAC filings. The Companies either were unable or unwilling to attempt to reconcile this disconnect in response to KIUC discovery in this proceeding.

I recommend that the Commission initiate an investigation to determine the correct line loss factors to utilize for retail and off-system sales in the FAC prior to the next two year FAC reviews for the Companies. I recommend that the Commission retain an independent transmission planning expert to assist it in acquiring the necessary information so that it can make the appropriate policy decisions regarding the proper allocation of line losses in the FAC from February 2002 forward. I further recommend that the Commission establish a process whereby the findings of the independent expert

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customers.

can be reviewed and assessed by the parties through one or more technical conferences with an objective of reaching a consensus recommendation for the Commission's consideration, approval, and implementation.

Q. How does the LGEE control area determine actual line losses?

A. The LGEE control area continuously balances its generation to match its load. Line losses are computed on an actual basis after the fact by the Companies.

Q. How do the Companies allocate their actual line losses for FAC purposes?

A. The Companies utilize a 1% loss factor for off-system sales in their FAC filings pursuant to prior Commission Orders. The Companies' actual losses, less the 1% allocated to off-system sales, are included in the fuel costs recovered from retail ratepayers.[2]

Q. Please describe the Normand study.

A. The Normand study was performed on behalf of LGEE by Paul M. Normand, a consultant with Management Applications, Inc. The Commission relied upon the

[2] As noted earlier, KU also recovers some fuel costs and line losses from its all requirements wholesale

original Normand report for the 1% line loss factor currently utilized in the Companies' FAC filings. In the most recent report, Mr. Normand concluded that the 1% loss factor utilized by the Commission for off-system sales was appropriate. The report stated that the study quantified the incremental line losses by removing the so-called "fixed losses" that were "virtually constant for all hours of the year irrespective of loading conditions." According to the report, the fixed losses include transformer core losses, conductor corona and insulator losses, and substation auxiliary energy use. I have replicated the most recent Normand report as my Exhibit___(LK-2).

Q. Did the Norman report provide the total system losses for the study period?

A. No. The total system line losses were not provided in the Normand report, although the incremental losses were computed by netting out the fixed losses, according to the study methodology described in the report. Consequently, it isn't clear how the average line loss results of the Norman study compare to the actual system losses for the study period or to the MISO study results.

Q. Please describe the MISO study.

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customers.

A. The MISO study was performed by the transmission-owner members of MISO utilizing a common methodology. The loss factors determined in the study represent average loss factors for control area loads. A representative of LGEE participated as a member of the Working Group that developed the line loss factors and performed a detailed review of the models utilized with reference to the LGEE control area. This was done to "ensure the most accurate possible representation of each MISO transmission-owner's system for purposes of this loss analysis," according to the Summary of the study. I have replicated this Summary of the study and the summary computations underlying the LGEE 2.221% MISO line loss factor as my Exhibit___(LK-3).

Q. Please describe the summary computations underlying the LGEE 2.221% MISO line loss factor.

A. The 2.221% MISO loss factor includes both fixed losses and those that vary according to loading, based upon the summary computations replicated in my Exhibit___(LK-3). During the winter load points, total system losses ranged from 2.383% to 2.978%. During the summer load points, total system losses ranged from 1.770% to 2.332%. The fixed losses include transformer no-load losses and auxiliary power, and corona and insulator losses. These losses represent less than one-tenth of the 2.221% total line losses over the six load points of the study, or only 0.183% of the total line losses. Thus, the variable losses appear to average 2.038% over the six load points.

Q. Do the results of the MISO and Norman studies appear consistent?

A. No. Although I am not a transmission planning expert, the results of the two studies appear to be widely divergent. The MISO study results appear to indicate that the average variable line loss rate over all hours is 2.038%, or approximately three times the 0.636% to 0.750% incremental loss rate indicated in the Normand report. The Normand report does not include sufficient data to reconcile the results of the two studies methodologically or mathematically.

Q. Were the Companies requested to reconcile the results of the MISO study and the Normand study?

A. Yes. The Companies were requested to reconcile the different results of the two studies by KIUC in discovery. The Companies either were unwilling or unable to do so, stating in their responses that the studies reflect "fundamentally different objectives and intent." Unfortunately, that response begs the issue and fails to describe or explain the different results for the benefit of the Commission. Regardless of the objectives or intent of the two studies, there should be no difference in the physical properties of the transmission system or the actual transmission losses, whether on an average or incremental basis. The relevant issue is to correctly quantify the effects of off-system sales on line losses, and in a manner that is consistent with the MISO environment.

Q. In general, is it your understanding that the greater the load on a transmission line, the greater the line losses?

A. Yes. Consequently, the last increments of load on the lines create the greatest losses, all else being equal. I have reviewed various materials that address transmission line loss, including an Edison Electric Institute ("EEI") report entitled *Electric Power Transmission and Wheeling,* prepared by Charles River Associates. I have replicated this report as my Exhibit___(LK-4).

The Introduction to this EEI report states that "This primer is intended to introduce nontechnical readers to basic concepts in electric power systems design, operation, transmission, and wheeling." This EEI report describes the general principle that more current results in greater line losses and provides a mathematical formula generally utilized to quantify the relationship between current and line losses. The report states the following:

> **Using Ohm's Law, one can show that for a given line (i.e., resistance size), more current results in greater losses. The exact formula is:**
>
> **Rate of Heat Production in a Line = Lost Power in a Line**
> $$= I \times I \times R = I^2 \times R$$
>
> **where I is the current in a line and R is the line resistance. Notice that power losses go up as the square of the current, so that a tenfold increase in current means 100 times as much power lost. This equation is the reason utility people sometimes refer to line losses as " 'i-squared-r losses.' "**

Based on the mathematical and physical concepts set forth in this EEI report, it appears that incremental sales cause line losses that mathematically are higher than the average. This EEI report appears to directly contradict Mr. Normand's conclusion that off-system sales produce line losses that are less than the average.

Q. **Should the retail load be solely responsible for the costs of fixed losses?**

A. No. Fixed costs and fixed losses are caused by all transmission system users and therefore are properly allocable to all users pursuant to the MISO OATT. Mr. Normand apparently disagrees with this principle, at least for FAC purposes.

Q. **Why should the Commission be concerned about the line losses utilized in the FAC for off-system sales?**

A. The Commission should be concerned that retail ratepayers do not subsidize the costs of off-system sales. If the appropriate line loss factor for off-system sales is the MISO average of 2.221% or some other average or incremental percentage, then the continued use of a 1% factor may result in the retail ratepayers subsidizing off-system sales through excessive FAC rates.

Q. Do you expect off-system sales volume to increase post-MISO?

A. Yes. With MISO's single transmission rate, the Companies' low cost generation can be exported to more markets economically than in the past. Therefore, off-system sale volumes likely will increase.

Q. Given the MISO line loss factor and the potential for cross-subsidization of the Companies' off-system sales by retail ratepayers through the FAC, how should the Commission proceed?

A. It is essential that the Commission have available objective advice regarding the correct quantification of lines losses on both an average and incremental basis in order to ensure that there is no subsidization of off-system sales by retail ratepayers. As such, I recommend that the Commission initiate a process to determine the correct line loss factors to utilize for retail and off-system sales in the FAC prior to the next two year FAC reviews for the Companies. I recommend that the Commission retain an independent transmission planning expert to conduct an operations audit pursuant to the Commission's authority in KRS 278.255 and report its findings to the Commission and other parties. I also recommend that the Commission convene one or more technical conferences for the parties to review and assess the findings of the independent expert and to attempt to resolve consensually the treatment of line losses for retail and off-system sales for FAC purposes. If the parties are not successful in resolving this issue consensually, then the Companies and intervenors can file testimony regarding the line loss issues in the Companies' next two year FAC review.

Q. What issues should the independent transmission planning expert address?

A. I recommend that the Commission charge the independent expert with the following tasks:

1. Provide an description of the LGEE transmission planning process in the MISO environment, including, but not limited to, the design, sizing, and expected operation of the transmission system components, with a particular emphasis on reliability and differences between native load and other load, if any.

2. Provide a description of the physics associated with current flows and line losses, including, but not limited to, fixed losses, and variable losses associated with incremental loads ramping up to as much as 50% in excess of the retail load.

3. Provide an independent quantification of the effects on LGEE average and incremental line losses of incremental loads of as much as 50% in excess of the retail load in increments of 10%.

4. Explain the apparent differences between the MISO and Normand studies, including differences in methodology, levels of fixed losses, levels of variable losses, levels of total losses, and whether it is relevant to consider the LGEE control area in isolation from MISO.

5. Recommend to the Commission an appropriate line loss factor to be assigned to off-system sales for FAC purposes.

Q. Does this complete your testimony?

A. Yes.

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AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF LOUISVILLE GAS & ELECTRIC CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)) CASE NO. 2002-00225)

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2002

002798

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY UTILITIES CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)) CASE NO. 2002-00224)
AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF LOUISVILLE GAS & ELECTRIC CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)) CASE NO. 2002-00225)

EXHIBIT ____(LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

002801

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Consumers
Kimberly-Clark
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

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RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

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Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

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**Expert Testimony Appearances
of
Lane Kollen
As of September 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.

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Expert Testimony Appearances
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As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

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Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

002809

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.

002810

**Expert Testimony Appearances
of
Lane Kollen
As of September 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

002811

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

002812

Expert Testimony Appearances of Lane Kollen As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

002813

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

002814

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

002815

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

002816

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms.	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

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Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

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Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements In projected test year.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.

002819

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) (Surrebuttal)	LA	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.

002820

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.

002821

Expert Testimony Appearances
of
Lane Kollen
As of September 2002

Date	Case	Jurisdict.	Party	Utility	Subject
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear llife extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02 (Supplemental Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission Statt	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization tariffs.

002822

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN EXAMINATION OF THE FUEL ADJUSTMENT	)	
CLAUSE OF KENTUCKY UTILITIES CO.	)	CASE NO. 2002-00224
FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)	
AN EXAMINATION OF THE FUEL ADJUSTMENT	)	
CLAUSE OF LOUISVILLE GAS & ELECTRIC CO.	)	CASE NO. 2002-00225
FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)	

EXHIBIT ____(LK-2)

002823

MANAGEMENT APPLICATIONS CONSULTING, INC.
2921 Windmill Road • Suite 4 • Sinking Spring, Pennsylvania 19608-1681 • 610/670-9199 • Fax 610/670-9190 • http://www.manapp.com

February 5, 2001

Mr. William A. Bosta
Director of Regulatory Management
LG&E Energy Corporation
220 West Main Street
Louisville, KY 40232

Dear Mr. Bosta:

This letter and the attached exhibits summarize the results of our incremental loss study for the LGEE integrated power system relating to LG&E and KU's Off System energy sales. The incremental loss results for the year 2000 are consistent with our prior loss studies for the Kentucky Utilities Company and the integrated LGEE power system.

The incremental loss study utilized eight separate power flow studies which were applied to the combined LG&E and KU Off System sales in a consistent manner as with previous incremental loss studies. In addition, a much more detailed analysis of incremental losses was performed on an hourly basis using the eight power flow loss results. These calculated hourly results were aggregated monthly to derive monthly incremental loss factors which were then weighted by the corresponding monthly Off System sales to derive a final annual incremental loss factor.

The results from these two separate loss analyses yield annual incremental loss factors which are below the currently approved level of 1% and are consistent with results from our prior incremental loss studies for each company. My recommendation, based on these loss results, is that the currently approved incremental loss factor of 1% be maintained as the appropriate loss factor for Off System sales by KU and LG&E.

Should you have any further questions, please give me a call.

Sincerely,

Paul M. Normand

PMN/rjp

11824 Jollyville Road • Suite 303 • Austin, Texas 78759-2322 • 512/331-1313 • Fax 512/331-4451

LGEE Incremental Loss Analysis

For Off System MWH Sales

February 5, 2001

Prepared by:

Management Applications Consulting, Inc.
2921 Windmill Road, Suite 4
Sinking Spring, PA 19608
Phone: (610) 670-9199 / Fax: (610) 670-9190

LIST OF EXHIBITS

LGEE Incremental Loss Analysis For Off System MWH Sales

INTRODUCTION

Energy losses occur in every piece of electrical equipment which carries electricity. The vast majority of these losses arise from resistance to current flowing through conductors and which vary with load and are referred to as variable or load losses. The other major component of losses is no-load or fixed losses. Fixed losses include transformer core losses, conductor corona and insulator losses and substation auxiliary energy use. The level of variable losses will vary according to loading conditions and other system factors such as the distribution of generation to meet load. By contrast, fixed losses remain virtually constant for all hours of the year irrespective of loading conditions.

In an incremental loss analysis, fixed losses must be netted out or removed from the results. This is most important since failure to remove these fixed non-varying losses will materially inflate the resulting loss factors and produce misleading and inconsistent results when applied to incremental non-firm sales, which are priced at incremental fuel costs.

The most direct approach to isolating the effect of fixed losses and incremental load additions is to initially establish a base case where the power system is modeled for the full requirement of the Company's native loads and relevant interconnections. The next step in the process is to simulate the impact of losses on the power system from the base case by incrementally increasing the load to represent various sales transactions and recording any differences in each of these calculations with respect to the base case.

INCREMENTAL LOSS CALCULATIONS

As part of my review of the losses related to Intersystem Sales, eight power flow case studies were performed to quantify the appropriate level of losses for incremental transactions. The loss calculations were prepared using an incremental export of 100 MW for each transaction to reflect a representative level of Intersystem Sales. These calculations were made using the Company's power flow model with a base case loading level for the summer of 2001 peak. From this information, incremental losses related to these sales were identified in the summer period. In order to evaluate any possible seasonal effects, an additional set of identical calculations were undertaken so that the remaining winter period was modeled. Exhibit PMN-3 provides the detail summary incremental loss results of these power flow studies for peak loading conditions of 100, 90, 70, and 40 percent for each season.

For purposes of my analysis, I used incremental loss factor calculations for a large portion of the year based on average loading conditions. This is a reasonable method based on my experience. In order to capture this very important aspect of the calculation and retain the higher seasonal loading conditions, power flows results were used in the calculations based on a 70% level for the summer and winter peak period. Exhibit PMN-1 presents the Company's monthly peaks as well as the corresponding monthly average demand levels, which were used as a guide in formulating my analysis. The off-peak calculations were based on a simple average of the summer and winter incremental loss results. The calculated incremental loss results presented in Exhibit PMN-4, Section I, line E, are reasonable for establishing a loss factor under varying load conditions throughout the year for all transactions.

In order to check the reasonableness of the incremental loss calculations described above, based on prior studies, a separate and more detailed incremental loss analysis was undertaken for each hour of the year using the eight power flow loss results. The procedure was to calculate an incremental loss factor for each hour using a piecewise linear representation of the eight loss factors representing power flows at 100, 90, 70, and 40% loading conditions. Using the 2000 load duration data and the eight power flow loss results separated into the summer and winter load period, a unique incremental loss was calculated for each hour of the year over a wide range of loading conditions.

The final calculations presented in Exhibit PMN-3 reflect the hourly incremental loss results for each month excluding Sundays and holidays. Exhibit PMN-4, Section II, incorporates the monthly incremental losses from Exhibit PMN-3 weighted by the monthly Off System sales from Exhibit PMN-2 to arrive at an annual incremental loss factor.

RECOMMENDATIONS

The incremental loss results for two separate analyses, as presented on Exhibit PMN-4, Sections I and II, show that the level of losses is below the currently approved 1% value. My recommendation is to maintain this level as a reasonable threshold to ensure full recovery of these losses based on my analyses as presented herein.

EXHIBIT PMN 1
LG&E and KU Combined
Monthly System Peaks

	2000	Monthly Peak (a)	Monthly MWH (b)	Monthly Average Demand (c)	Percent of Annual System Peak (d)
1	January	5,335	2,819,239	3,789	60.11%
2	February	4,850	2,461,297	3,536	56.10%
3	March	4,157	2,409,093	3,238	51.36%
4	April	3,862	2,213,922	3,075	48.78%
5	May	5,174	2,576,411	3,463	54.93%
6	June	5,989	2,905,426	4,035	64.01%
7	July	5,983	3,033,988	4,078	64.69%
8	August	6,304	3,135,605	4,215	66.85%
9	September	5,248	2,561,348	3,557	56.43%
10	October	4,794	2,438,619	3,278	51.99%
11	November	4,746	2,498,515	3,470	55.05%
12	December	5,387	3,059,496	4,112	65.23%
13	**Annual Peak/Total**	**6,304**	**32,112,959**		
14	12 Mo. Avg.	5,152		3,656	
15	Percent Annual Peak	81.73%		57.99%	

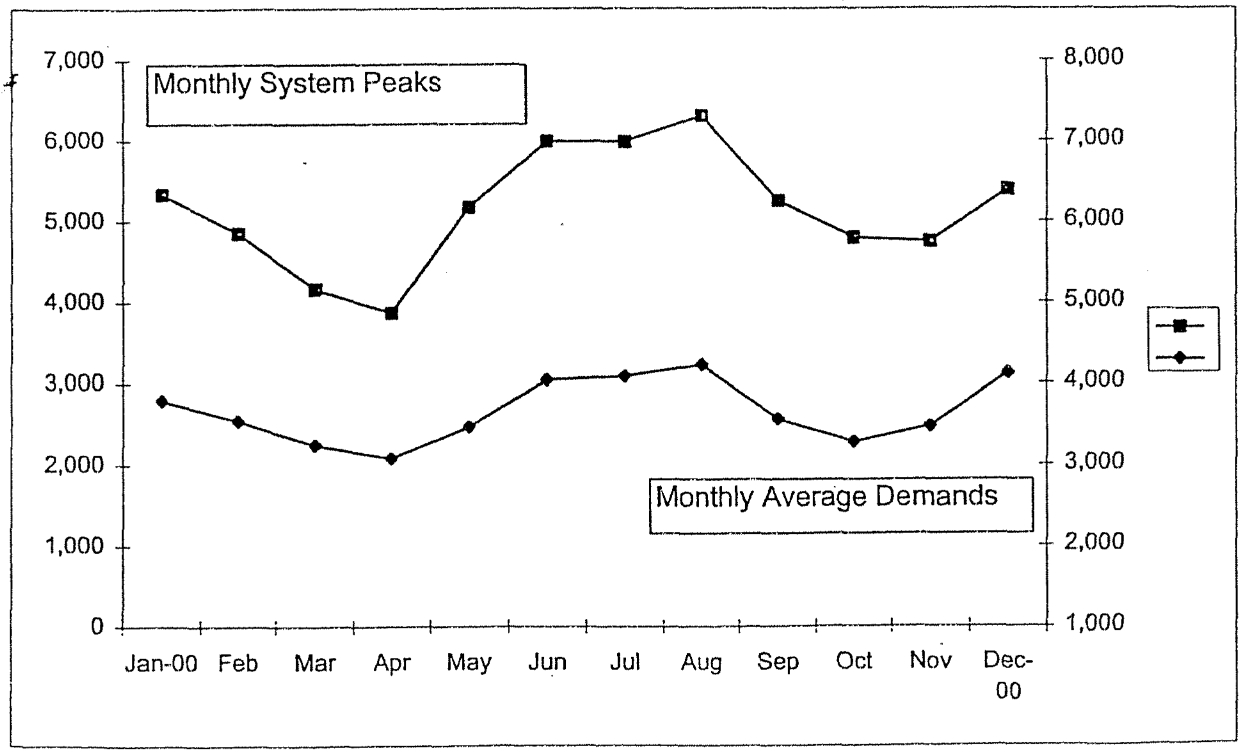

EXHIBIT PMN 2
LG&E and KU Combined
Monthly Off System Sales

		1999		2000		1999,2000
		MWH Sales	Percent of Annual Total	MWH Sales	Percent of Annual Total	Average Percent
1	January	582,124,000	5.73%	1,179,982,000	12.46%	9.09%
2	February	535,683,000	5.27%	772,999,000	8.16%	6.72%
3	March	754,742,000	7.43%	1,101,262,000	11.63%	9.53%
4	April	963,171,000	9.48%	663,161,000	7.00%	8.24%
5	May	756,509,000	7.45%	471,072,000	4.97%	6.21%
6	June	832,154,000	8.19%	639,363,000	6.75%	7.47%
7	July	466,736,000	4.59%	453,484,000	4.79%	4.69%
8	August	790,230,000	7.78%	510,267,000	5.39%	6.58%
9	September	947,029,000	9.32%	973,290,000	10.28%	9.80%
10	October	1,266,991,000	12.47%	1,039,903,000	10.98%	11.72%
11	November	1,065,256,000	10.48%	805,707,000	8.51%	9.50%
12	December	1,199,877,000	11.81%	860,872,000	9.09%	10.45%
13	Annual Total	10,160,502,000	100.00%	9,471,362,000	100.00%	100.00%

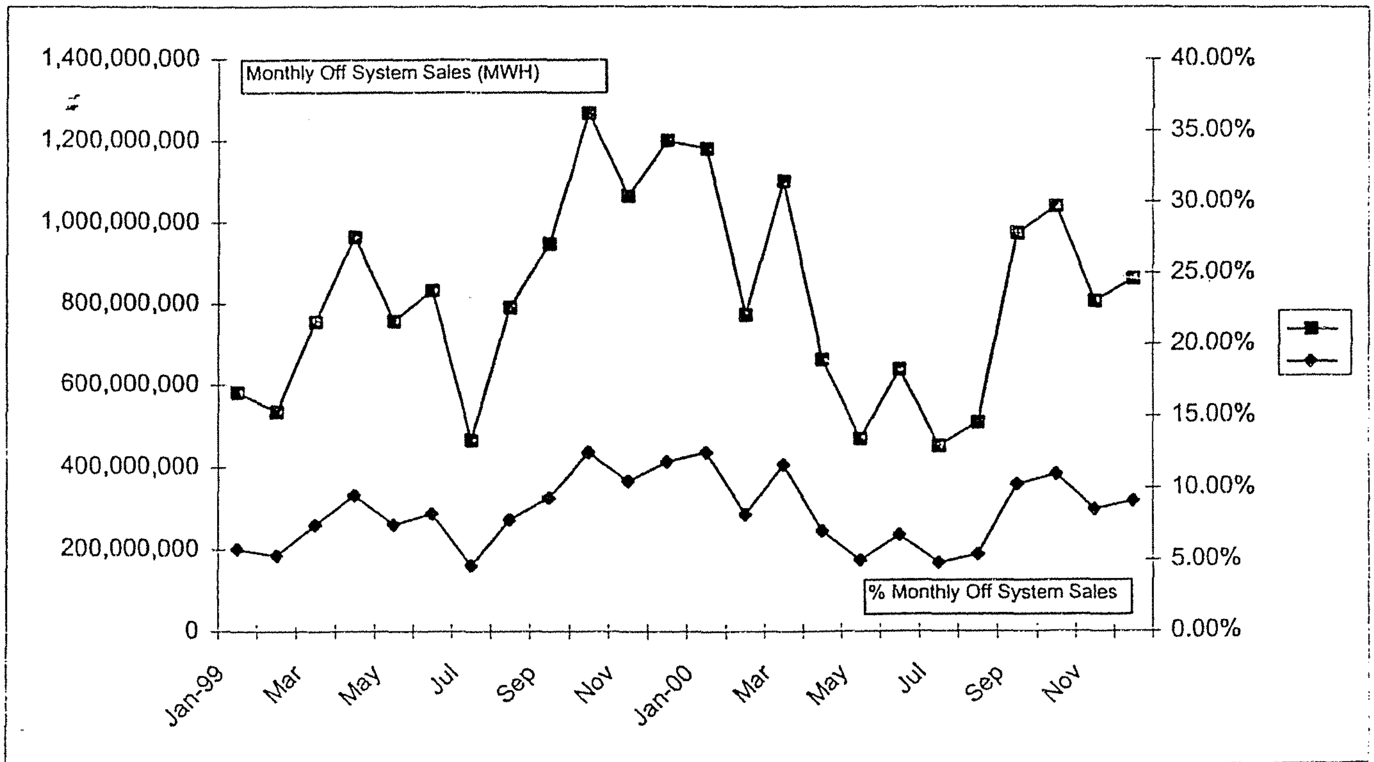

EXHIBIT PMN 3
LG&E and KU Combined
Power Flow Incremental Loss Results

I. Power Flow Incremental Losses

Case	Summer MW Load	Summer PU Load	Summer Incremental Losses
01-100	6,360	1.00	1.35
01-090	5,724	0.90	1.11
01-070	4,466	0.70	0.77
01-040	2,552	0.40	0.04

Case	Winter MW Load	Winter PU Load	Winter Incremental Losses
0102-100	5,426	1.00	1.61
0102-090	4,883	0.90	1.33
0102-070	3,798	0.70	0.85
0102-040	2,178	0.40	0.11

II. Monthly Average Incremental Losses

Months	Average Incremental Losses
JAN	0.930
FEB	0.769
MAR	0.630
APR	0.283
MAY	0.445
JUN	0.624
JUL	0.654
AUG	0.692
SEP	0.447
OCT	0.364
NOV	0.747
DEC	1.038

III. Seasonal and Annual Average Incremental Losses

Average Summer Incremental Loss = 0.504 MW per 100 MW export

Average Winter Incremental Loss = 0.819 MW per 100 MW export

Average Annual Incremental Loss = 0.634 MW per 100 MW export

EXHIBIT PMN 4
LG&E and KU Combined
Incremental Loss Results Monthly Off System Sales

I. Seasonal Analysis

Off System Sales		Summer	Winter	Off Peak	Total
A.	100 MW (at 100 % peak load)	1.35	1.61		
B.	100 MW (at 70 % peak load)	0.77	0.85		
C.	100 MW (at annual average)			0.634	
D.	Off System Sales Percent (Exhibit PMN 2)	28.54%	35.76%	35.70%	100.00%
E.	Weighted Incremental (Rows B and C x Row D))	0.220	0.304	0.226	**0.750**

II. Monthly and Hourly Analysis

Months	Average Incremental Losses	Monthly Off System Percent	Weighted Monthly Loss Calculation
JAN	0.930	9.09%	0.085
FEB	0.769	6.72%	0.052
MAR	0.630	9.53%	0.060
APR	0.283	8.24%	0.023
MAY	0.445	6.21%	0.028
JUN	0.624	7.47%	0.047
JUL	0.654	4.69%	0.031
AUG	0.692	6.58%	0.046
SEP	0.447	9.80%	0.044
OCT	0.364	11.72%	0.043
NOV	0.747	9.50%	0.071
DEC	1.038	10.45%	0.108
TOTAL		100.00%	0.636

Average Annual Loss Factor **0.636**

III. Recommendation 1.000% Average Annual Incremental Loss factor

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN EXAMINATION OF THE FUEL ADJUSTMENT	)	
CLAUSE OF KENTUCKY UTILITIES CO.	)	CASE NO. 2002-00224
FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)	

AN EXAMINATION OF THE FUEL ADJUSTMENT	)	
CLAUSE OF LOUISVILLE GAS & ELECTRIC CO.	)	CASE NO. 2002-00225
FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)	

EXHIBIT ____(LK-3)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to KIUC's Post Conference Data Request Dated August 23, 2002

Case No. 2002-00225

Question No. 2

Witness: Paul Normand

Q-2. Please provide a copy of the MISO study utilized to derive the 2.22% line loss rate used in the MISO OATT tariff for off-system sales. If the MISO study cannot be provided or does not describe the methodology utilized, then provide a detailed description of the methodology and provide an illustration of the computations that were performed along with a description of the data and assumptions utilized.

A-2. Attached is a four-page summary of the calculation methodology used by MISO to calculate losses. Also attached, in spreadsheet form, is the data used in determining, and the precise calculation of, LG&E/KU's line loss factor. Both the summary and the spreadsheets are on file at the FERC. Any additional information regarding MISO's line loss study can be obtained from the MISO website at www.midwestiso.org.

MISO Loss Study Summary
April 26, 2000

Introduction
This report provides a summary of the calculation of average loss factors by twelve transmission-owner members of the Midwest Independent Transmission System Operator, Inc. (MISO). Pursuant to an April 6, 1999 Stipulation in FERC Docket Nos. ER98-1438, et al. (as modified), the transmission owner members of the MISO are obligated to jointly file with FERC to change, or justify retention of, their transmission loss factor by the earlier of either April 30, 2000 or 90 days prior to implementation of transmission services by the MISO. This report summarizes how these average loss factors were determined.

To meet this obligation, the participants have agreed on a common methodology for determining their average loss factors. The common methodology uses the same equations and the same models of the power system to determine the average loss factor for each of the twelve companies. This common approach allowed the calculation of control area average loss factors on the same basis and also provides consistency with the MISO's overall loss recovery methodology.

Loss Factor Equation
The loss factor equation used by all twelve companies in this filing is defined below.

$$\%\ Loss = \frac{100 \times (Load\ losses + No\text{-}load\ losses)}{(Transmission\ Area\ Load + (Exports + Parallel\ Flow))}$$

Load Losses: These are losses incurred by current flowing through conductors and transformers on the transmission system. Only losses on transmission elements, as included in each participant's rates for FERC-jurisdictional transmission service, are included in this calculation. These losses are determined from the common power flow model for six loading conditions for each participant. Generation Step-Up (GSU) transformer losses were identified separately and are not included in the transmission load losses.

No-load Losses: These are losses that are incurred by only the energization of electrical equipment such as transformers and high voltage wires, and include transformer core losses, corona and insulator losses, and may include auxiliary substation use (transformer cooling equipment load, etc.). These losses are not represented in the powerflow models used in this analysis. These losses are included in a separate tabulation. No-load losses associated with GSU transformers were not included.

Transmission Area Load: For each MISO transmission-owner member, this represents the electrical load served by the transmission system to customers (wholesale and retail) within the company's control area. The values for each control area are calculated using values for area generation, scheduled area imports, GSU load losses and area non-transmission load included in the powerflow models. This calculation assumes that all scheduled power imports are required to serve control area load.

MISO Loss Study Summary
April 26, 2000

Exports: For each MISO transmission-owner member, this represents energy being exported to areas outside of the company's control area, from energy sources within the company's control area.

Parallel Flow: For each MISO transmission-owner member, this represents the incremental power flowing through the company's transmission system that is caused by any transaction which is contracted with the MISO. Parallel flows through a transmission company with a participation factor of less than 3% are not included, consistent with the proposed MISO methodology for loss compensation.

Summary of the Loss Study Procedure

To initiate this common filing, the MISO Transmission Owners formed a Working Group consisting of a representative from each transmission-owner member of the MISO. This Working Group (referred to as the Loss Study Working Group or LSWG) was charged with developing a common methodology and calculating loss factors for this filing based on the common methodology.

The first step taken by the LSWG was to agree on a common loss factor equation as described in the Introduction of this report.

The next step was the selection of common power flow models to perform the loss study. The LSWG agreed to use the MAIN (Mid-American Interconnected Network) Transmission Assessment Study (TAS) power flow summer and winter cases for this purpose because they were developed recently and have been reviewed more rigorously than any other powerflow models available. The MAIN Transmission Assessment Study Group (TASG) builds these two power flow cases each year. One case is built to represent expected conditions during the summer peak season. The other case is built to represent expected conditions during.the winter peak season. All known firm transmission reservations for the season being studied are modeled as energy transactions in these cases. In building these cases, MAIN coordinates with other reliability regions such as MAPP, SERC, ECAR and SPP to insure accurate modeling of the power system and transactions in the respective regions. These cases are built as part of seasonal studies that are performed twice each year to review transfer capability and overall reliability of the regional transmission system in the Midwest portion of the Eastern Interconnection. In addition to their other functions, these power flow models also calculate load-related transmission system power losses.

The 1999 TASG summer case and the 1999/2000 TASG winter case were used to quantify the load-related losses for this summary. Each LSWG representative performed a detailed review of these models with reference to their respective areas. Modifications were made to add more detail to the TASG case to ensure the most accurate possible representation of each MISO Transmission-owner's system for purposes of this loss analysis.

MISO Loss Study Summary
April 26, 2000

To enable the calculation of an average loss factor representing the entire summer or winter period, four additional cases were developed from the summer and winter TASG cases. These four additional cases represent load levels of 50% and 75% of the peak for each season. In total, six cases were built to determine the load-related losses.

In addition to building the power flow cases, no-load losses, exports and parallel flow were also tabulated. Each LSWG member was responsible for tabulating the subcategories of no-load losses, i.e. transformer energization losses and auxiliary power use and transmission line corona and insulator losses. A summary of these results is included in Appendix C.

In regards to transmission line corona and insulator losses, all members utilized a single average kW/mile factor for transmission lines of the same voltage level in this calculation. The kW/mile factors utilized for the various voltage levels were obtained from the "EPRI Transmission Line Reference Book 345kV and Above", Table 7.7.1 (page 327). No-load losses were assumed to be constant for all load levels studied. A summary of the tabulation of no-load losses for each member company is shown in Appendix C.

To identify exports and parallel flows, all of the transactions included in each of the MAIN TASG cases were identified. Each LSWG member reviewed the transactions and identified those transactions that are expected to be contracted with the MISO ("In", "Out", or "Through"). .

Transmission Participation Factors (TPF) were calculated from the summer and winter TASG cases. These participation factors were applied to each MISO transaction to determine the sum of export and parallel flow for each MISO Company. A list of the Transmission Participation Factors determined for both the summer and winter case is shown in Appendix B. The results of this TPF calculation assign a distribution factor of 100% for the source and sink system for each transaction. The 100% response for each sink system was excluded from the parallel flow calculation because these MWs are already included in the Transmission Area Load. In accordance with the filed MISO loss methodology, participation factors of less than 3% were not included in the determination of parallel flows. Exports are included in the results of this calculation since the TPF for the exporting company, which is the source company, is 100%.

For each company, two sets (summer and winter) of exports plus parallel flow were determined from these calculations. The same export and parallel flow estimates were used in all cases within each respective season.

The LSWG utilized the load-related losses calculated from the six power flow cases combined with the calculations of no-load losses, exports, and parallel flows to produce loss factors for the 50%, 75%, and 100% load levels for each season for each company. These six loss factors reasonably represent the variation of losses with load for both summer and winter for each company. The three loss factors for each season were then

MISO Loss Study Summary
April 26, 2000

calculated according to piece-wise linear functions defined by the 50% and 75% losses, and the 75% and 100% losses.

A unitized load duration curve for each company was developed from actual 1999 hourly load data. Once this was done, the calculation based on linear functions described above was utilized to estimate the load losses for each hour. This was performed for summer and winter using the loss data from the summer and winter power flow cases, respectively.

The hourly loss factors calculated using these linear functions were then averaged into one factor using a simple average of the seasonal hours to determine the final average loss factor.

MISO Loss Study Loss Calculation Spreadsheet

utility:	LG&E Energy Corp.
edited:	M. G. Toll 10/19/01

	Summer Cases 100% of Peak	Summer Cases 75% of Peak	Summer Cases 50% of Peak	Winter Cases 100% of Peak	Winter Cases 75% of Peak	Winter Cases 50% of Peak
Transmission Zone Load-Losses (MW)	165.3	108.8	66.3	181.2	125.5	74.7
Transformer No-Load Losses and Auxiliary Power (MW)	9.0	9.0	9.0	9.0	9.0	9.0
Corona and Insulator Losses (MW)	1.8	1.8	1.8	1.8	1.8	1.8
Company Total Transmission Losses (MW) [numerator]	176.1	119.6	77.1	192.0	136.3	85.5
Generation (MW)	6,516.4	4,813.3	3,115.2	5,522.6	4,007.0	2,491.7
Interchange (MW)	-286.9	-286.9	-286.9	-529.9	-529.9	-529.9
GSU Load Losses (MW)	14.1	8.3	3.3	10.7	5.8	2.5
Transmission Zone Load-Losses (MW)	165.3	108.8	66.3	181.2	125.5	74.7
Non-Transmission Load (MW)	192.0	144.3	96.4	116.0	87.1	58.1
Total Company Transmission Load (MW)	6,431.9	4,838.8	3,236.1	5,744.6	4,318.5	2,886.3
Export and Parallel Flow (MW)	1,121.3	1,121.3	1,121.3	702.7	702.7	702.7
Company Total (MW) [denominator]	7,553.2	5,960.1	4,357.4	6,447.3	5,021.2	3,589.0
Discrete Loss Factors	2.332%	2.007%	1.770%	2.978%	2.715%	2.383%
Seasonal Loss Factors	1.859%			2.589%		
# of Hours	4416			4344		
Annual Loss Factor	2.221%					

"Total Company Transmission Load" = "Generation" - "Interchange" - "GSU Load Losses" - "Transmission Zone Load-Losses" - "Non-Transmission Load"

The "Discrete Loss Factors" are calculated from the equation:
(Company Total Transmission Losses)/(Total Company Transmission Load + Export and Parallel Flows with T.P. Factors > 3%)

The "Seasonal Loss Factors" are determined by using a piecewise-linear function of the "Discrete Loss Factors" to calculate hourly loss factors based upon the 1999 annual load profile of each utility.

The "Annual Loss Factor" is calculated by using a weighted average of the two "Seasonal Loss Factors" based upon the number of hours in each season.

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MISO Loss Study Loss Calculation Spreadsheet
utility: LG&E Energy Corp.
edited: M. G. Toll 4/07/00

Voltage Level (kV)	Corona Losses (kW/mile)	Line Miles (mi)	Total Corona and Insulator Losses (MW)
345	3	489.9	1.5
500	6	56.9	0.3
765	13		0.0
		Total	1.8

Notes:
1) Corona losses per mile (kW/mi) were obtained from Table 7.7.1 on page 327 of the "Transmission Line Reference Book - 345kV and Above (second edition)" published by the Electric Power Research Institute in 1987

Transmission Transformers No-Load Loss (MW)	7.4
Transmission Transformers Auxillary Power Use (MW)	1.6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

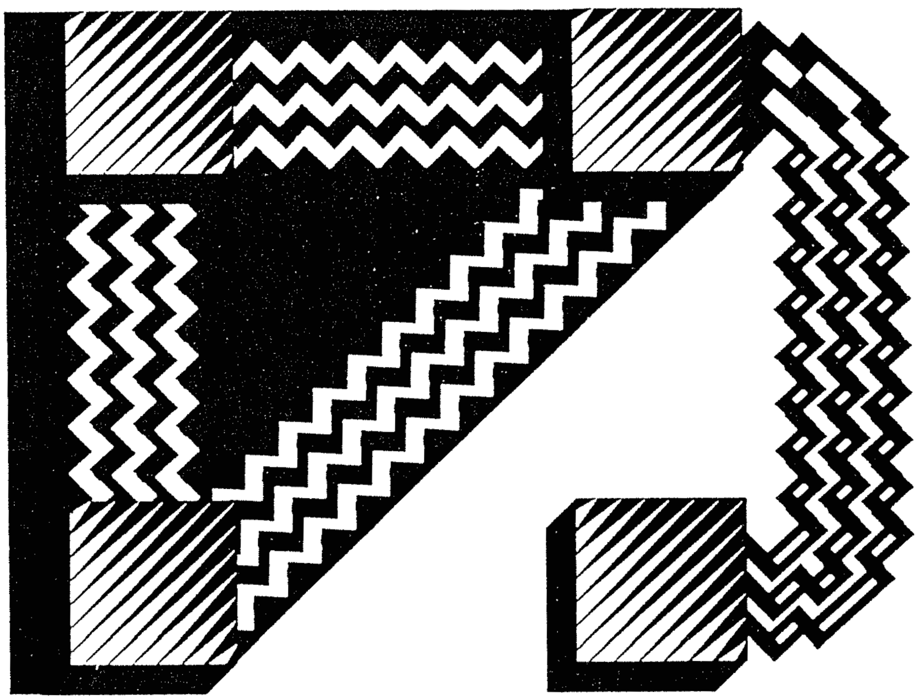
In the Matter of:

AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY UTILITIES CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)) CASE NO. 2002-00224)
AN EXAMINATION OF THE FUEL ADJUSTMENT CLAUSE OF LOUISVILLE GAS & ELECTRIC CO. FROM NOVEMBER 1, 2001 TO APRIL 30, 2002	)) CASE NO. 2002-00225)

EXHIBIT ____(LK-4)

Electric Power Transmission and Wheeling

A Technical Primer



By Peter S. Fox-Penner, Ph.D.
Charles River Associates

Edison Electric Institute

Table of Contents

INTRODUCTION

This primer is intended to introduce nontechnical readers to basic concepts in electric power systems design, operation, transmission and wheeling. Unlike engineering books, it will not presume that readers have a strong background in mathematics and physics. For additional technical detail, readers are advised to consult more advanced works on the subject.

The single most important objective of the primer is to give the nontechnical reader an intuitive understanding of how power systems operate and how power wheeling takes place. Unfortunately, use of the term "wheeling" (as well as analogies to other regulated industries) often leads to the misconception that power can be "shipped" from A to B like a crate of fruit. This is simply not a proper analogy. The behavior of electric circuits and, more importantly, the type of power systems we have designed render this analogy too simplistic for productive discourse.

This exposition builds an understanding of transmission through a brief introduction to electric circuit theory. The treatment is neither technical nor mathematical, but it requires patience. Although it may seem that the definitions of volts and watts are of little relevance to those who want to make practical, non-engineering use of this knowledge, it is precisely the simple concepts that explain transmission best. Frequent use is made here of an analogy between the electric transmission system and a system of water pipes. This example is not in perfect accord with the physics of hydraulic systems, but it is intuitive and useful.

Chapter 2 of this primer discusses voltage, current, energy, and power.

See the *Bibliography* for several suggested titles.

Chapter 3 covers simple circuit concepts and introduces transmission system load flow and transmission system adequacy. The operation of power systems is discussed in Chapters 4 and 5, first in conceptual language and then with reference to the actual procedures of generation dispatching and load scheduling. Chapter 6 introduces alternating-current circuit concepts such as reactive and apparent power, and Chapter 7 offers a brief summary and conclusion. Readers interested in a more detailed treatment of the subjects covered in this primer may wish to consult the Bibliography that follows Chapter 7.

Most readers are familiar with the concepts of alternating current (AC) and direct current (DC). In the former, electric charges regularly switch back and forth a certain number of times per second (frequency); in the latter, all charges flow in one direction. Although electric systems make use of alternating current, most of the concepts that are required for an understanding of wheeling and transmission are more easily conveyed using DC circuits. For this reason, no further mention is made of AC circuit concepts until Chapter 5.

Readers who are unfamiliar with these concepts should not attempt to digest all of this at once. Two or three partial readings are better, because they afford the reader a chance to review prior material before proceeding to new concepts.

CURRENT, VOLTAGE, POWER, AND THE BASIC DESIGN OF ELECTRIC UTILITY SYSTEMS

Voltage and Current

Our discussion of electric power systems begins with the twin concepts of electrical potential, or voltage, and current. Many people who are not engineers vaguely sense that voltage is equated with the size of machines and the amount of work they do, but what precisely is the connection? Similarly, many people have changed fuses or flipped the switch in a circuit breaker. At such times, they may have noticed that these devices accommodate different amounts of current, measured in *amperes*. But why have two measures of electrical size or strength?

Voltage and current are related to potential and kinetic energy. To put it simply, voltage is a form of *potential energy*, which is the *potential to do work*. A convenient analogy can be drawn using a water pipe, to which is attached any device you choose — say a food grinder. The pressure in the pipe represents potential energy, energy that is lost when water is released into a water wheel attached to the food processor. Remembering conservation of energy, the potential energy is changed to the same amount of kinetic energy, which is used to grind up some carrots. The more pressure in the pipe, the greater the potential energy and the more carrots we can grind and put in the carrot souffle.

If electrical voltage is analogous to the pressure in the pipe, electrical current is analogous to the flow rate of water in the pipe. Consider two pipes with identical widths and pressures, but different sizes of food processors hooked up to them. The huge food processor turns very slowly, so water in the pipe does not flow very fast. The smaller processor turns quickly, and the water flows snappily through the pipe.

The difference between hydraulic and electrical systems is that in the latter an electrical field provides the electrical potential analogous to pressure. This field causes charged particles to flow at a rate that depends on the resistance they are facing, much like the resistance the food processors gave the water.[1] The pipe analogy suggests that voltage is important, because it indicates the amount of work we can ultimately accomplish. Current seems only to be an indication of the rate at which things are happening, which is actually a reasonable interpretation.

This modest explanation is sufficient to convey the essential purpose of the almost inconceivably large and complex electric power systems of the world. Almost all these systems are designed to provide a *constant voltage* at your home or business. The power company is providing you with a given *potential* to do work. The amount of work you actually do depends on the *load* or the number of devices you plug in and use.

Work, Energy, and Power

Thus far we have been talking about voltage and power in the abstract, using the analogy of a pipe that has a certain pressure inside it and a certain flow rate. The relationship between the pressure in the pipe, the flow rate, and the resistance put up by the water wheel has a direct electrical analog called Ohm's Law, which is described by the following equation:

$$\frac{\text{Voltage (volts)}}{\text{Resistance (ohms)}} = \text{Current (amps)}$$

Table 1 shows this relationship for our hydraulic analogy, its electrical description, and finally its precise mathematical form. The idea is quite simple: for a given amount of pressure or potential, more resistance will result in less current flow. The harder it is to budge the water wheel, the less water will flow at any given pressure.[2]

In scientific terms, the sole purpose of an electric power system is to enable users of electricity to accomplish things, or do work. Work has a very precise technical definition that can be phrased differently for each type of energy system. In our hydraulic example, work can be measured by the pounds of carrots we grind up or by some other physical measure. But electricity is used for grinding, motors, refrigeration, lighting, heating and many other things, so how can we measure work?

In electrical circuits, it is easier and more important to first measure the *rate* at which you are doing work. If you multiply the rate by the time spent at that rate, you get the work accomplished. In electrical circuits, the

---

[1] Electrical current was once viewed as tiny units of negative charge (electrons) moving down a wire. [illegible] physics has made this view passé. Electrical engineers confuse issues further when they describe current as positive charges moving in the opposite direction from that in which electrons would move. This sort of current is called hole current. Any one of these views of electrical current are sufficient for the purposes of our discussion.

[2] *In an electrical circuit, voltage is measured by a device called a voltmeter and current by an ammeter. Resistance is then calculated using the relationships between current, voltage and resistance of Ohm's law. There is no device that directly measures resistance. Resistance is discussed in more detail in Chapter 3.*

TABLE 1

OHM'S LAW: THE RELATIONSHIP BETWEEN CURRENT, VOLTAGE, AND RESISTANCE

Hydraulic Analogy	Electric Description
The greater the resistance, the less flow you observe at a given pressure.	For a given electrical potential (voltage), a greater circuit resistance results in a smaller current.
Units of Measure and Symbols	Electrical Equation
Electric Potential: Volts (V) Electrical Current: Amps (I) Electrical Resistance: Ohms (R)	$\frac{V}{R} = I$

rate at which work is being done (or energy is otherwise being transformed in some way) is called *power*.

Power is important in electrical systems because it sets a limit on most components of electrical systems. An electric motor has a limit to the rate at which it can accomplish work. Assuming it doesn't wear out or burn out, there is no strict limit on its work — if you want more work, simply run it longer at any sustainable rate. Similarly, a generator has a limited rate of energy delivery and a power transmission line has a maximum *rate* at which electrical energy can flow through it to its load. Almost everything in a utility system is sized by its *power capacity* (often simply *capacity*).

In DC electrical circuits, power is quite easily related to voltage and current. Power, measured in *watts*, is voltage (in volts) times current (amperes). Note the difference between this relationship and Ohm's Law:

Power Equation	Power (watts) = voltage (volts) × current (amps)
Ohm's Law	$\frac{\text{Voltage (volts)}}{\text{Resistance (ohms)}}$ = current (amps)

Why is the product of a pressure concept and a flow rate concept a power concept? The fact that electrical current is the rate of flow of charges suggests that the power equation might be indicating a rate of energy transfer. As it happens, every time a charged particle moves due to the influence of an electric potential, work is done. The work done is proportional to the number of volts and the number of charges that move, which we'll measure in bundles called *coulombs*. So work or energy, which is measured in *joules*, is proportional to volts times coulombs.

Note the similarity between the work equation and the power equation:

Power (watts)	= voltage (volts) x current (amps)
Energy or work (joules)	= voltage (volts) x charges (coulombs)

These two equations look quite similar. First of all, they both begin with potential in volts. If power is really the rate at which energy is transferred, then we should be able to express the second equation as a rate by making it "per second." This means dividing any amount of work done (in joules) by the number of seconds it took. Comparing the two equations in this form, we have:

Power (watts)	= voltage (volts) x current (amps)
Energy or work per second (joules per second)	= voltage (volts) x charges per second (coulombs per second)

These two equations are in fact now identical. An ampere, which we know is a rate of flow of charges, is defined as one coulomb per second, and a watt is one unit of work (joule) per second. Therefore, in order to compute power we need only know voltage and current. To know the amount of work done, we need to keep a cumulation of voltage times current at each moment and cumulate them over time.

The units of power used in the utility industry are watts, often with the prefix kilo (meaning *thousands*) or mega *(millions)*. These are all measures of *capacity*, i.e., *maximum energy transfer rate*. You can easily compute the amount of energy used by multiplying a power level by the period over which it is used. This is precisely how units of energy are expressed in the industry: if you transfer at a constant rate of one kilowatt of power for one hour, you cumulate energy equal to:

1 kilowatt x 1 hour = 1 kilowatt-hour

Voltage, Power, and the Design of Our Electric System

We now understand what it means to say that the electric power system provides a constant electrical potential to do work at our homes and businesses. But just what is it that we pay for? Are our electric bills based on the amount of current we draw at the constant voltage? What about our maximum momentary demand, or power? Or, because these quantities are related by equations, does it even matter?

Most power bills are based on the amount of *work* you do with electricity, i.e., the cumulative electric energy you "consume" during the month.[7] The power company figures this out by installing a meter that watches the current go by and keeps a cumulative record of the amount. The power company knows that the voltage was constant, so if they know the current, they can figure out how intensively you ran your appliances during the past month. In other words, the power company makes the following use of the above equations: since power is voltage times current, and voltage is constant, power can be figured easily by measuring current. Since energy is the cumulation of power, a meter that cumulates current flow can be used to calculate energy used during a period.

To recapitulate, utility systems have this rather unique form:

1) Voltage is constant;

2) The customer's choice of load determines the maximum rate of power demanded; and

3) Utilities must build systems large enough to supply at the maximum rate (power capacity).

The fundamental design of modern electric power delivery systems resulted largely from the economic and technical evolution that has taken place since the late 1800s. The nature of contracts between power systems and their customers is one in which the power supplier must meet a challenging burden: it must maintain a constant voltage at all times, no matter what loads customers opt for.[5] Other than establishing voltage levels and a maximum current level that can be used by customers, the energy supply decisions of the utility and the energy use decisions of customers are coupled only through the monthly utility payment.[6] This has unleashed a powerful process of economic development based on the continuous availability of all desired electric power.

Between 1920 and the recent past, utility regulation served to further entrench this view of the obligations of utility suppliers and users. Utility regulation is often described as a compact in which the government allows only one utility to serve in an area, in exchange for the utility serving all area needs without excess profit or discrimination. The technical translation of this "obligation to serve" is that utilities must plan their generation and transmission systems to keep up with a load over which they exercise little control.

We put "consume" in quotes because energy is never used up; it is only converted in form. (This is the meaning of the scientific principal that energy is always conserved.) Advanced readers should note that this example is based on traditional residential tariffs, which are based on energy used and do not typically incorporate a demand charge. (Nonresidential customers are typically charged for both energy used and maximum power demanded.) It also neglects customer charges and other important components of utility bills.

This is an exaggeration. Your fuse box limits the amount of current you can draw from your utility. When a new fuse box is installed and connected to the utility, an implicit or explicit agreement made with the utility establishes your maximum current. The utility keeps track of this when new customers move into homes with existing meters, so customers don't have to discuss this regularly with utilities. However, this is an important issue for utility planners, as they must plan ahead to be able to supply the aggregate of all maximum currents.

There are, of course, some exceptions. Many utilities have established load management programs whereby the utility can directly or indirectly control a proportion of the load of some customers. For example, some utilities have installed radio-controlled switches on customer water heaters and air conditioners, allowing the utility to switch off these appliances during periods of peak demand.

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Regulation has grown to require utilities to consider their obligation on both a momentary and long-term basis. Over the course of a year or many years, utilities must have enough capacity to serve *all loads*. However, the obligation to serve has also been interpreted to mean that utilities must run their systems so that voltage is supplied continuously and constantly, at a precise voltage and frequency, with a minimum of interruptions. Like its longer-term counterpart, this aspect of the compact originated with one specification for the product offered by utilities to customers and ultimately became an economic and technical necessity.

The requirements for voltage constancy, accuracy, and non-interruption are commonly referred to as reliability requirements. While the term "reliability" connotes technical requirements, in the broader sense it means the economic and operational ramifications of the short-term aspects of the "obligation to serve." Although important links exist between the short- and long-term pictures, particularly for utility planners, much of our attention will focus on examples with time frames of seconds or minutes.

One of the purposes of this primer is to place into clear focus the relationships between the technical characteristics of the electric power system and the pricing, contracting, and regulation of electric transmission. The discussion thus far is intended to demonstrate this relationship at its most primal level: the relationship between the technical nature of electricity and the fundamental terms of service offered by utilities.

The second point of this discussion is that the model of universal, constant-voltage service is central to utility planning. Legal and regulatory changes are being made on the margin, but changing the model itself would require dramatic changes in technology, regulation, and, most importantly, in the very concepts of energy production and energy use.

Until such changes occur, we will inhabit a world with constant-voltage, you-choose-the-current electric power systems. In this world, utilities plan and operate their systems to provide extremely high levels of reliability, as defined above. We will now see that the job of maintaining constant voltage for a massive number of relatively unfettered customers is a remarkable engineering triumph and a fascinating subject to study.

DC CIRCUIT CONCEPTS AND LOAD FLOW

The equations we presented in Chapter 2 allow us to understand a great deal about power systems. To explore this further, we return to the water pipe analogy. Figure 1A depicts a simple "water circuit." We know that if we put gauges on the pipe anywhere between point A and B, we will measure the pressure and the water flow. There may be some friction in the pipe that could cause the pressure to drop a little, but ignore this for the moment. If at some time we find that a rate of energy transfer (power) of X Megawatts is flowing down the pipe, conservation of energy immediately tells us that the same amount of power must be 1) coming out of the pressure generator, and 2) going into the load. If not, one part of the system would be accumulating or storing energy, and nothing can continue to store energy indefinitely.

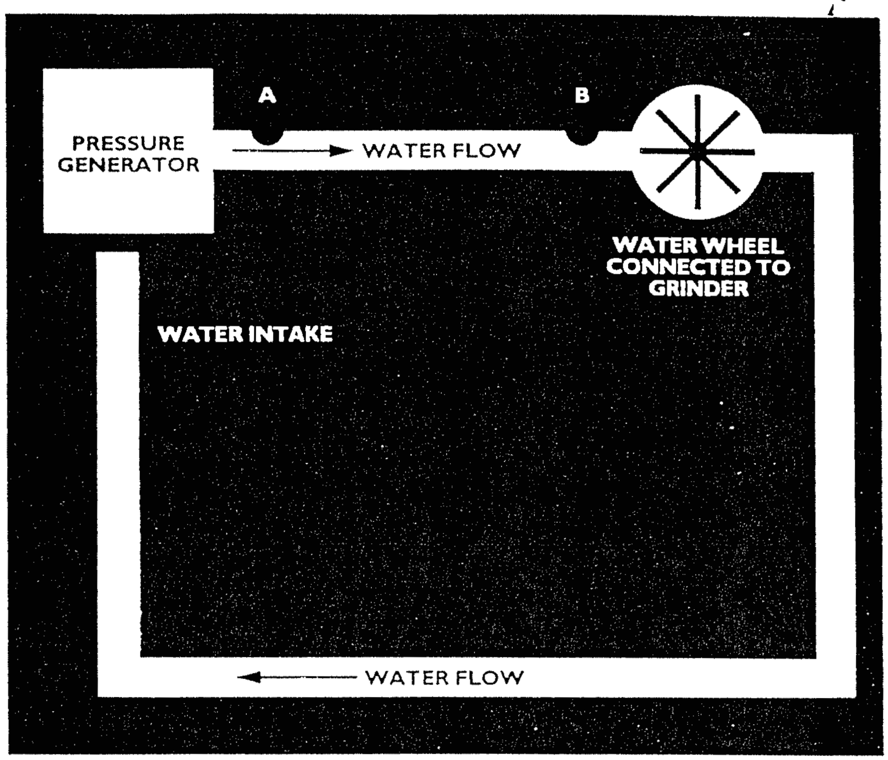
Figure 1B depicts an electrical circuit much like the water circuit in Figure 1A. In an ideal circuit, there is no "friction" in the electrical lines and there is no energy storage. Then, by conservation of energy, the rate of power flow out of the generator equals power in the wires which equals power consumed by the load. If not, the energy rates would be unequal and the "slower" part of the circuit would accumulate (or store) energy.

The actual situation in the circuit is more like the diagram in Figure 1C. The same current flows through the line and the load, which both have some resistance. Since both resist the power, some work is done in each — but much more is done in the load. Ohm's Law and the power equation tell us how much energy is used in each part of the circuit. Total energy (power) generated equals the total consumed in the line plus the load.

Later we will see how energy storage is very important, but the importance of line losses or "friction" is immediately obvious from Figures 1A and

Figure 1A

[illegible]



A
B
PRESSURE GENERATOR
WATER FLOW
WATER WHEEL CONNECTED TO GRINDER
WATER INTAKE
WATER FLOW

[illegible]

FIGURE 1B

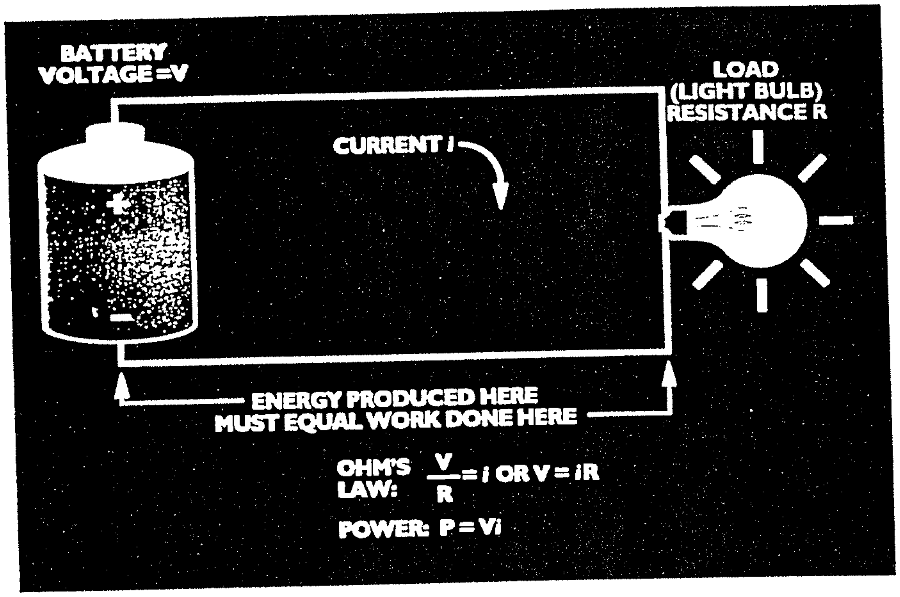
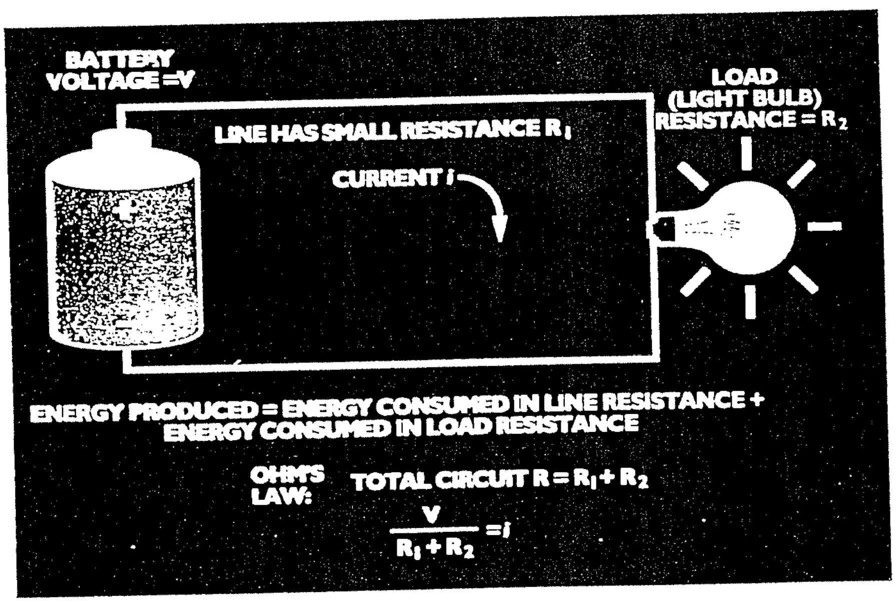


FIGURE 1C



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1B. If some of the energy is used in the line to do (unneeded) work in the form of heat, there is less energy for the grinder in Figure 1A or the load in Figure 1B. This loss will show up as a drop in voltage as the current travels down the wire, much as the pipe's friction could reduce water pressure over long pipe lengths. Rewriting Ohm's Law as V=IR, we can compute the amount of pressure lost, V, as the product of the amount of current in a wire and its resistance.[7]

These losses are a waste of energy — they simply heat up the transmission wires and the air around them. Engineers have devised a number of clever ways to reduce these losses, as we will discuss in Chapter 5. Moreover, loss reduction is not just a function of the type of wire used, it is also a function of the geometry of the system and the way the system is operated.

In the real world, power systems take energy from many different generators through a crisscrossed "grid" of wires to thousands upon thousands of loads of varying sizes. If we could draw a hydraulic analog of a real system, it might look something like Figure 2A. A number of pressure generators, P1 - P5, pressurize the water, which flows through a system of pipes of varying widths. In this figure, the huge, diverse number of loads is shown as a small number of fairly large loads, but this won't harm the illustration.

Recall that Chapter 2 of this primer stated that one of the absolute requirements of an electric utility is that voltage stay approximately constant at every load. In the water system, this means that we have to design and operate the system so that pressure is *always* P at every load, even though we aren't sure exactly how large each load will be. Let's examine how we might approach the design and operation of this system.

Using conservation of energy, it is relatively easy to figure out the total amount of pressure generators we will need — it is simply the total amount of load on the system plus the total amount of friction losses. Since we measured the amount of resistance in each of the sections of pipe, we know the amount of losses that will occur at every flow rate. If we can do a good job of forecasting the total amount of load customers will have, we can build the proper amount of pressure-generating capacity, P.

When we start to think about the number and type of pipes needed for this system to provide constant pressure, the solution is not so simple. First, we know that pipes have a certain maximum capacity (energy transfer rate). Second, we know that losses depend on the particular type (resistance) of the pipe and the variation in loads. We cannot lose too much pressure in the pipes, or pressure at the load will fall below the permissible level.

Now assume that we have constructed adequate pressure capacity and that we have also managed to design a piping system that operates correctly over a wide variation in total loads demanded by our customers. (We need to allow for the variation in total loads on weekends and evenings, in hot or cold weather, etc.) In this system, water is flowing in a complex pat-

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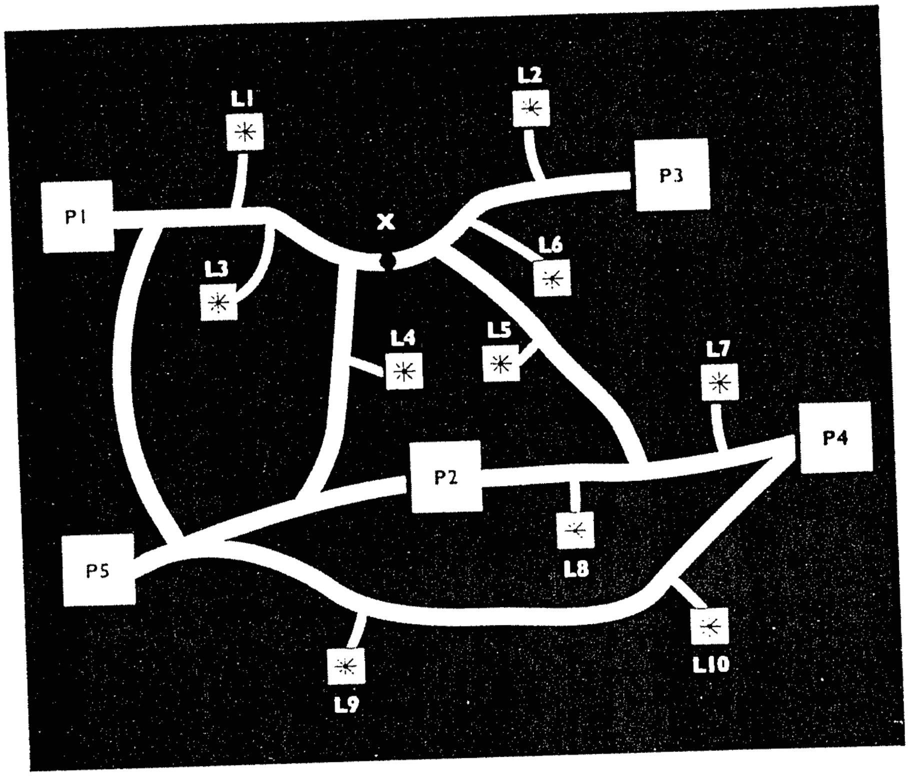
[7] Resistance is a property of a wire that depends on its material, geometry, etc. For any given type of wire, we can use the method mentioned earlier to determine its resistance.

FIGURE 2A

[illegible]



[illegible] These [illegible] to the [illegible] not [illegible] diagrams. [illegible]

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tem through the pipes to meet all the above conditions, including no overloaded pipes.[3] We don't have to calculate where every molecule of water that leaves each generator goes, because conservation of energy and constant pressure conditions with no overloads guarantee that the system is working. As long as this occurs, it really doesn't matter what water goes down what path.

A final obligation of our hypothetical water utility makes all of this much more important and much more difficult. What if a pipe breaks at Point X in Figure 2A? Look at the geometry of the network in Figure 2A. We have designed in enough redundant pipes to make sure that every load in the circuit still has water. But how do we know that no overloads occur and that every load pressure does not deviate from pressure P?[4]

You can now better understand the job that befalls the designers and operators of electric transmission systems. Figure 2B depicts an electrical network styled after the hydraulic network of Figure 2A. The constraints on design and operation of this system are very similar to those in the hydraulic example. First, we must have sufficient generating capacity to supply total power demanded at all times, that is, forecasted load plus line losses. As in the hydraulic example, assume for the moment that this capacity exists.

Second, no line can carry too much power. A transmission line that carries too much power overheats, just like any other device. Remember we found that some of the energy in the circuit was used for "work" that consisted of heating the line and the surrounding air. Using Ohm's Law, one can show that for a given line (i.e., resistance size), more current results in greater losses. The exact formula is:

$$\text{Rate of Heat Production in a Line} = \text{Lost Power in a Line} = I \times I \times R = I^2 \times R$$

where I is the current in a line and R is the line resistance. Notice that power losses go up as the square of the current, so that a tenfold increase in current means 100 times as much power lost. This equation is the reason utility people sometimes refer to line losses as "i-squared-r losses."

In real electric systems, transmission systems are designed to prevent lines from overheating, which is dangerous and may ruin the lines. Each section of line is protected by circuit breakers, much like the fuses or breakers that protect the wires in your home. Overloads will "trip" lines out of service, i.e., the circuit breakers will open and remove the line from the transmission system.

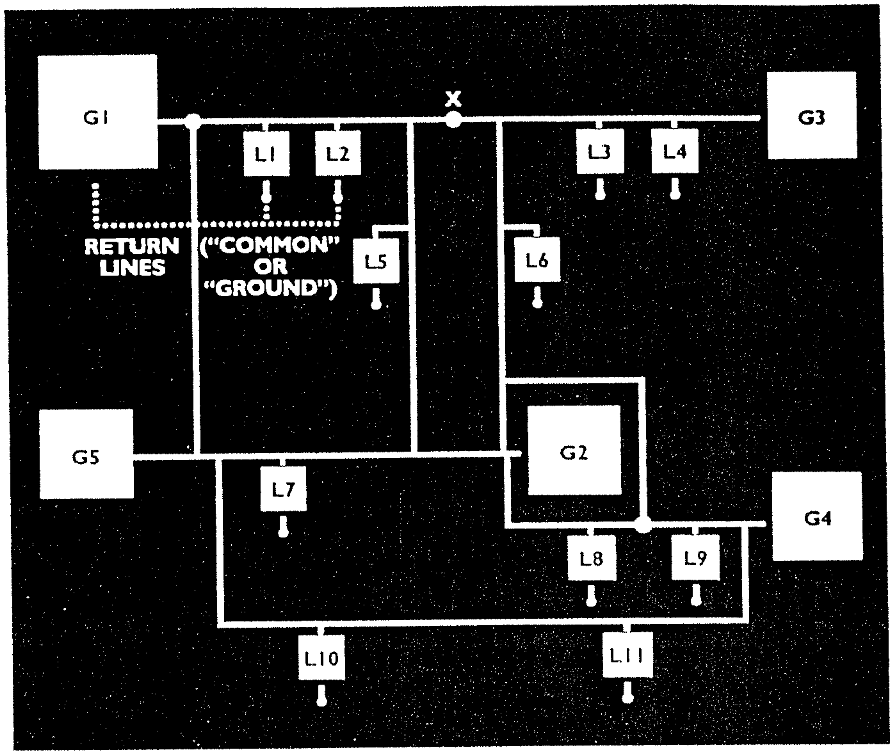
Intuitively it seems a little more difficult to design an electric power system like that in Figure 2B than the water system in Figure 2A. Matching generating capacity to total load seems to be the same. The equivalent of

[3] Most water pipes don't overload like electrical transmission lines. To make this analogy, allow for overloaded pipes: think of brittle ceramic or thin plastic pipes. If these conduits are exposed to too much pressure, the pipes rupture ("overload"), water drains out of the circuit and no work is done. Similarly, when an electric transmission line overloads, the circuit shuts down and no work is accomplished.

[4] As explained in the previous footnote, the pipes in this example can overload and interrupt water flow, much like transmission lines.

Figure 2b

Simplified Electrical Network with Lossless Transmission Lines



[illegible] are aggregated electrical loads or [illegible] that complete [illegible] Point X is a [illegible]

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"different widths of pipes" in electric systems would seem to be "wires of different resistance," but so far we have been vague about whether this is really the only measure of line capacity. Also, do we have to design the system so that it still delivers constant voltage and no overloads if there is a break at Point X? If so, it seems that we have to be able to model where the current is flowing both before and after the break, so we can keep track of i-squared-r losses in each line. Otherwise, they'll overload and shut down; and, instead of having one line out of service, the whole system will shut down.

The work just described is called a *load-flow calculation* (or simulation, if a computer is used), and it is exactly what transmission planners do. The bases for these calculations are computer programs that contain the locations of all lines in the system, all loads (aggregated into load centers, as in Figure 2B), and all generators. The computer solves a set of equations that are based on little more than conservation of energy, Ohm's Law, and Kirchoff's Laws, to calculate the voltage and current at every point in the circuit. Every connection point in the circuit that could have a different V or I is called a *bus*. Present-day computer programs using matrix-solution techniques are capable of solving load flows for systems with thousands of buses and transmission lines.

Now that we have a rudimentary understanding of electrical transmission system design and the dangers of overload, let's reexamine the major design requirements. The point of the exercise is to demonstrate that *design and planning* are inextricably linked to successful *operation*, which is a moment-to-moment activity in power systems.

We first reexamine our assumption that the system had sufficient power capacity to instantaneously supply an energy rate large enough to maintain voltage at all loads. As part of this, we forecasted the sum total of loads, including losses. However, what determines the size and location of the generators that together will have the capacity to equal the total load? To answer this, we have to solve the network calculations; they can tell us, for each generator location, how much power must be delivered. So, in a sense, generation planning occurs after you have located your loads and network flows. In reality, planning occurs around a system that is already operating. The actual process is therefore iterative: project future total load, locate a hypothetical plant, simulate load flows, see if lines are overloaded, and if so either relocate the plant, build more lines, or do both.

Although we have omitted economics from the discussion so far, you can be sure that economic considerations are extremely important in planning exercises of this sort. At each point in the iterative process, computer programs are used to estimate the cost of the generation or transmission improvement and the impact of the new investment on the cost of power

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Kirchoff's Laws refer to any electrical network that is described in terms of its nodes (connection points, or buses) and loops (complete circular electrical paths). *Kirchoff's Laws state that the algebraic sum of all currents entering a node is zero, and the algebraic sum of all voltages in a loop is zero.* These relationships make it possible to estimate network conditions in very complex networks with many nodes and loops.

The precise extent to which these two concepts are linked is a key element in the current policy debate over [illegible] wheeling.

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A new investment must pass a cost/benefit test, with costs and benefits defined to suit the particular exercise. In general, however, regulation requires that utilities strive to meet the objective of adequate generation and transmission capacity at the lowest reasonable overall cost to society.[12]

When a system is designed to have adequate generating and transmission capacity under normal operating conditions, it is said to have *adequacy*. The North American Electric Reliability Council (NERC), an industry-wide group that sets reliability guidelines, defines adequacy as:

> **Adequacy** is the ability of the bulk power electric system to supply the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.[13]

Since it takes several years to build a new generator or a line, the kind of planning studies we are talking about are conducted by forecasting total loads, costs, and capacities over many years — usually a minimum of ten. This is a relatively long time horizon over which to plan. It is somewhat ironic that a system can be operated optimally in the short term only if it has been designed properly for the long term. In the following chapter we will learn more about short-term system operation. This will allow us to return to this point in Chapter 6 with a better understanding of the relationship between long-term planning and short-term operations.

[12] See H.G. Stoll, Least-Cost Electric Utility Planning (New York: John Wiley & Sons, 1989), for an excellent detailed description of modern utility planning procedures.

[13] "Reliability Concepts in Bulk Power Electric Systems," NERC (February 1985): 8.

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POWER SYSTEM PLANNING AND OPERATIONS: A FIRST LOOK

Economic Dispatch and Ordinary System Operation

Now we are ready to increase our understanding of the relationship between planning and operation by bringing economics into the picture. When discussing the concept of system *adequacy* in the preceding chapter, not much attention was paid to the cost of producing electricity. Whether for an entirely new (hypothetical) system or for additions to an existing system, we calculated load flows and then located generators and/or transmission system upgrades where they were needed.

If we also want to minimize the cost of electricity, we add a whole new set of economic constraints to this previously all-electrical problem. All actual generators have different costs per unit of energy that are strongly dependent on the time pattern of generator use. Remember that customer loads vary greatly over the course of a day, week, and year, so some generators are in use constantly ("base-load facilities") while others are on occasionally ("intermediate" or "cycling" capacity) or only operated on days with very high loads ("peaking" capacity or "peakers"). Designing the system for adequacy is mostly a function of the periods when the load is very high. Designing the system for least total cost over one or more years depends on the accumulation of generating costs incurred over all periods and load conditions.

Consider the system depicted in Figure 2B. Assume that in periods of low demand, only one generator is needed to maintain adequacy. It seems obvious that if we want to minimize costs we ought to run the cheapest generator and turn the others off. If the system is *adequate* at much higher loads, when all generators are needed, it seems likely that nothing will overload now (but we can check it with our load-flow program if we desire).

As load increases from its minimum, the next generator turned on is the next cheapest. Again we should check for adequacy. If the system capacity is adequate, this is the most economical way to operate. This method of turning on (or *dispatching*) generators using the lowest-cost units first is called *economic dispatch*. It is the way all utilities decide the scheduling of their units on an hour-to-hour basis. Each utility or group of utilities establishes a *control area*. This determines the boundaries of the system that will be modeled for adequacy; all flows into and out of this area are considered interchanges with other areas. Within this area, a single center controls all plants and monitors transmission lines on a minute-to-minute basis. [4] The control center knows the operating cost of each plant and is armed with data acquired from many load-flow studies. Figure 2C shows the network of Figure 2B drawn as a control area, with interties to other control areas.

This discussion should not leave the mistaken impression that there is no overlap between design for adequacy and least-cost operation. Often load-flow studies indicate that the existing system is imperfect, so the hypothetical least-cost dispatch cannot really occur. Moreover, there are a number of adjustments that can be made in the transmission system to change power flows and improve dispatch. (So far, we have not mentioned that transmission lines are adjustable. We will address this issue at a later point.) The limits to these economic adjustments are determined by the now-familiar technical constraints.

It is the job of a utility's system planners to develop a resource plan that provides system adequacy at the lowest reasonable cost. [5] Load-flow models and the iterative process described above are the tools used to design for adequacy. To estimate the economic impact of running a system or of adding a generator or line, a computer program called a production cost simulator is used. This program simply takes a hypothetical utility system and the time pattern of customer loads as inputs and predicts the cumulative costs of power production months or years into the future. For the most part, these models assume the system is always adequate, i.e., that the hypothetical dispatchers on the hypothetical system have no transmission-related constraints on dispatch. The disparities between these two sets of planning tools highlights the need for system planners to continually juxtapose the competing requirements imposed by adequacy and economics. [6]

The time frame for these planning studies and modeling efforts is on the order of ten years. The planner is trying to forecast the operation of the system years into the future because the generators and lines constructed today will greatly influence the future operation of the system.

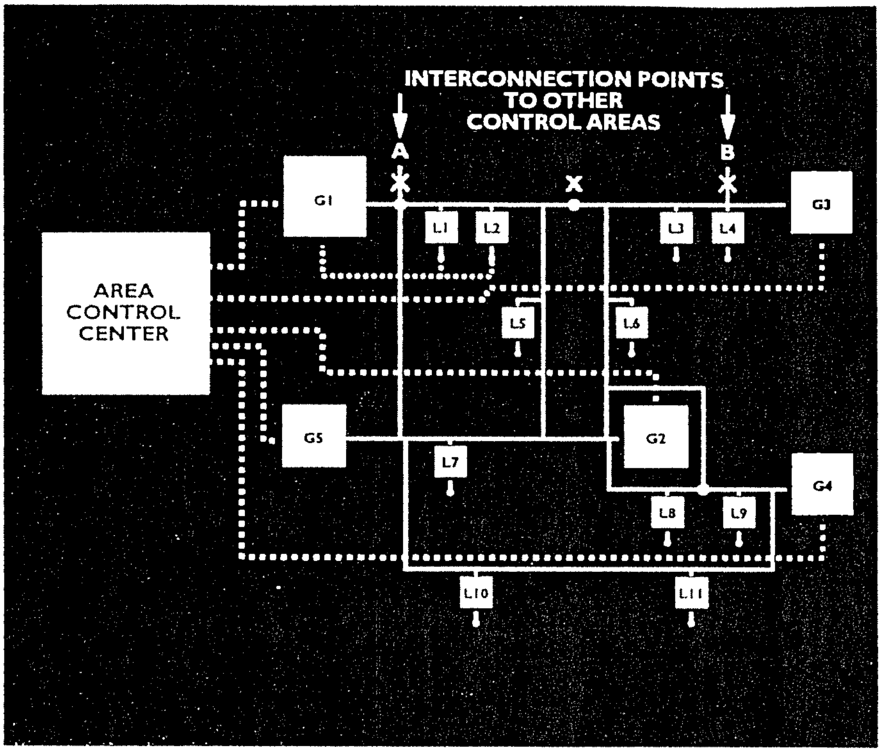
This is a simplification useful at present. In Section [illegible] we will examine the control of power systems and the role of the area control center in more detail.

Recently, many utilities have adopted a form of <u>least-cost planning</u> or <u>integrated resource planning</u>, which include consideration of both supply-side (generation) and demand-side (load management) options in development of a resource plan.

Computer programs have recently been introduced that integrate economic dispatch and transmission considerations. These are new, highly sophisticated tools.

FIGURE 2C

SIMPLIFIED ELECTRICAL NETWORK
SHOWN AS A CONTROL AREA



This is the same network as shown in Figure 2B but it is tied to other control areas via interconnections at points A and B. Inside the control area the level of output of all plants is con- [illegible] the control center. The control center [illegible] must continually [illegible] points A and B [illegible] customer demand [illegible]

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TABLE 2

NUMBER OF CONTINGENCIES IN THE INSTITUTE FOR ELECTRICAL AND ELECTRONIC ENGINEERS (IEEE) RELIABILITY TESTING SYSTEM (RTS)

Type of Contingency	Level 1*	Level 2**	Level 3***
Generator Outage	32	528	5,488
Transmission Line Outage	38	741	9,177
Generators and Transmission Lines Together	70	2,485	57,225

*A single contingency.
**One or Two simultaneous contingencies.
***One, Two, or Three simultaneous contingencies.

The RTS is a circuit model of a hypothetical utility system used for testing reliability assessment techniques. For example, a utility planner may want to measure the probability that the RTS system will experience a blackout if two transmission lines fail at the same time. This table indicates that the RTS hypothetical system has 741 potential combinations of two lines that could fail at the same time. Thus, any planning study which looks at the potential outage of two lines at the same time must examine 741 different scenarios. Similarly, a planning study that looked at the effects of one generator and one line outage simultaneously must consider 2,485 possible scenarios. This suggests that conducting reliability assessments for a utility system with hundreds of transmission lines and multiple generators is a complicated and difficult process.

SOURCE: R. Billington and R.N. Allan, *Reliability Assessment of Large Electric Power Systems* (Boston, MA, Kluwer Academic Publishers, 1988), 115.

Contingencies and System Stability

So far our discussion has concentrated on a world of normal operating conditions and has ignored the final and most frightening design/operation criterion: sudden failures in transmission lines or generating stations. In utility jargon, the failure of a component is called a *contingency*.

Contingencies can involve situations such as generators suddenly going off, transmission line short-circuits or *faults* that cause the line's circuit breakers to open, voltages exceeding the system maximum level that also cause breakers to open, or a pure failure of a circuit breaker. Table 2 shows the number of contingencies associated with the generation and transmission systems in a particular system called the "Reliability Testing System" (RTS).

The RTS is a circuit model of a hypothetical electric utility much like Figure 2B which is used by electrical engineers to compare reliability calculations. The numbers in this table show the number of possible combinations of "things that can go wrong." The number of possible failures of individual items (Level 1) equals the number of items in the test system, i.e., 32 generators and 38 transmission lines. Notice that the number of ways two or three different things can go wrong grows quite large, relative to the number of generators and lines.

Contingencies of one sort or another are an everyday occurrence in large power systems. The only time utility customers realize that a contingency has occurred is when the contingency leads to an interruption in service, i.e., an outage. The reason why commonplace contingencies rarely result in outages is that each control area has been designed to survive not just one, but several simultaneous contingencies without violating system limits. This means that in addition to all the adequacy and least-cost planning and operation, planners must use their load-flow calculators to simulate the effects of every possible line failure in the entire area. If you want even more reliability, you must simulate and plan for any two failures, or three or four. How many should you plan for? It depends on how reliable you want your system to be. The standard procedure is to choose levels of two or three line failures and four generator failures. The idea is that the more contingencies you plan for, the lower the probability that you'll have an outage. However, the usual measure of reliability is not the *number* of contingencies you plan for, but rather the resulting *probability of an outage*. Engineers refer to an outage as a "loss of load" because an outage means that some customer loads are not being served, i.e., the system has intentionally shut some customers off to keep the rest of the system from overloading.[7] The most common measure of reliability is therefore the "loss of load probability" or LOLP and this is a primary design objective for system planners.[8]

The need to plan for contingencies imposes a significant additional set of constraints on the transmission planner. To maintain reliability, the transmission system contains many redundant lines and multiple pathways. Planners are careful not to put too much power in any one line, or to put too many lines close together, where a single lightning bolt could suddenly trip all of them out at once. The need to keep failures independent is one factor that limits increases in the amount of transmission that can be put in existing transmission corridors in order to minimize land-use and environmental impacts.

Thus far we have talked of contingencies as they affect transmission lines. It is certainly true that transmission lines fail frequently; it is also true that overloaded lines shut themselves down. With improper system design or operation, the failure of one line will overload others, causing them to shut down, and, in turn, causing others to overload and shut down. In extremely simplified terms, such a "cascading failure" caused the largest and

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[7] Engineers call this "shedding load."

[8] *For more information on measures of reliability, see Billinton and Allan (1988), Chapter 2, and Stoll (1989), Section [illegible].*

most famous blackout in the United States to date, the New York City blackout of 1965. This blackout prompted the utility industry to organize NERC and to adopt many of the contingency planning procedures we have been discussing.

There is, however, another danger from contingencies that is even more serious. Assume that the line at Point X in Figure 3A breaks but that we've done a good job of transmission planning, so the remaining transmission system can handle the rearranged flows. Moreover, let's assume that load-flow calculations indicate the power emanating from each generator is as shown prior to the contingency. To simplify this example, we assume transmission lines have no energy losses.

After the contingency, assume the situation is as depicted in Figure 3C. The lines are all OK, but notice that each generator is producing a drastically different amount of power. Remember that we are talking about power, which is the instantaneous flow of energy, and recall that in order to maintain voltage, power flow must continue without even the slightest interruption. There is no storage of energy in the system, so if users continue their pre-contingency rate of use, the same amount of total power must be delivered after the contingency.

The problem with the transition from Figure 3B to Figure 3C is that even if the transmission system remains within its limits, generators can't change their rate of power delivery immediately. Why? Generators are immense rotating machines that are continuously fed by huge boilers or other sources of mechanical energy. The rotating mass of a turbine stores mechanical energy and the amount of energy stored depends on its size and speed of rotation. Because conservation of energy applies to everything, in the case of generators the energy going in must equal the energy going out plus energy stored up.

We have not yet talked about alternating current, but the utility system generates current that swings from one direction to another 60 times per second. The frequency of the electricity is precisely related to the speed at which the turbine is rotating. And remember, the speed also sets the amount of energy stored.

Imagine what happens when the amount of power demanded from a generator suddenly goes up or down. The boiler feeding the turbine doesn't know that a line break has occurred, so it keeps feeding energy into the turbine. But the energy going out has changed instantly, so the difference has to be made up in the amount stored in the rotating mass of the turbine. To store more energy the turbine turns faster, and vice versa. So at a minimum the frequency of the power coming out of the turbine changes, and if there is too much energy stored or too rapid a change, the turbine will shut itself off to protect itself — much like transmission lines will trip circuit breakers when overloaded. (Moreover, transmission systems are set to trip before generators are critically affected. If you have a choice, it is more economical and faster to restore a transmission line than a damaged power plant.)[a]

---

[a] As a precautionary measure, utilities always keep several plants turned on and ready to produce power within minutes. These plants are called "spinning reserves."

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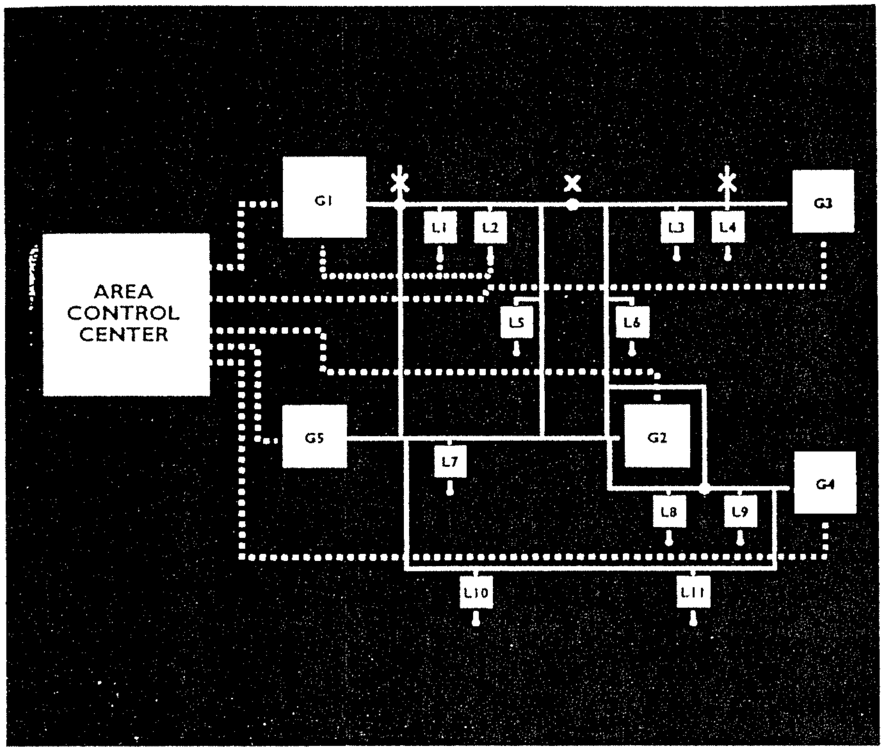
FIGURE 3A

SIMPLIFIED ELECTRICAL NETWORK
SHOWN AS A CONTROL AREA



This is the same network as shown in Figure 2B, but it is tied to other control areas via inter- [illegible] dis- [illegible]

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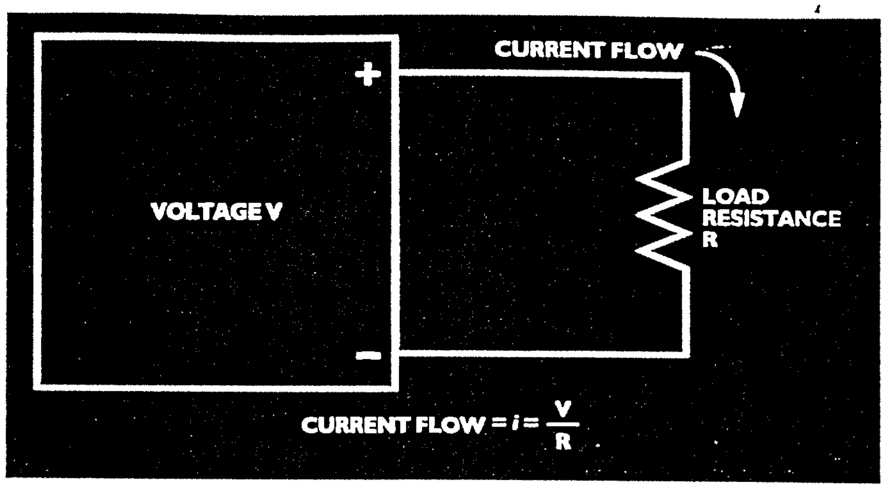
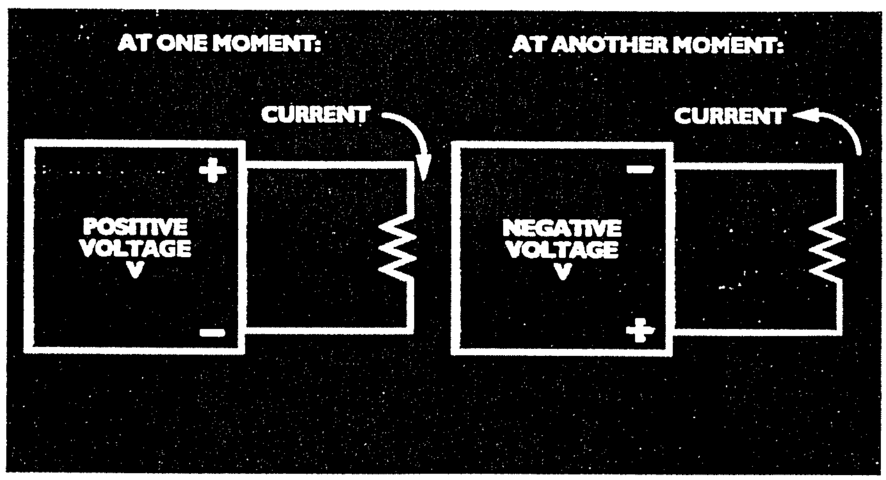
FIGURE 4A



[illegible] below. [illegible] constant. This [illegible]

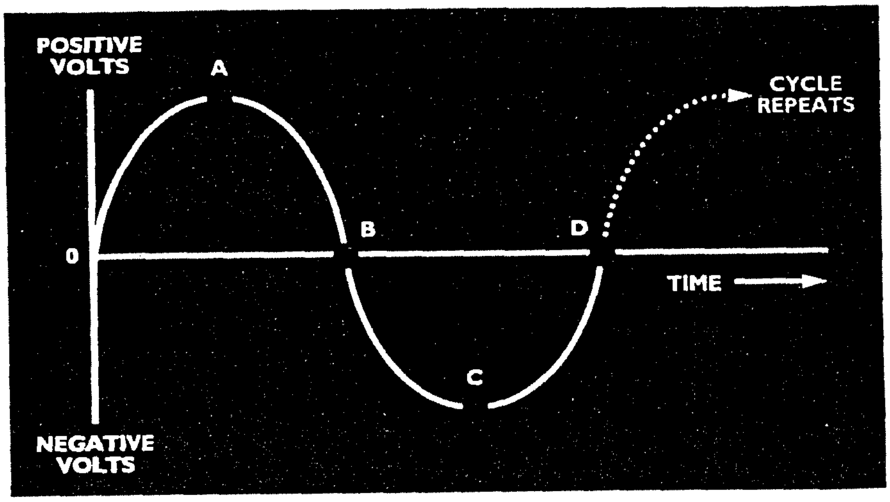
FIGURE 4B



[illegible] current will rise [illegible] reverses current [illegible]

FIGURE 4C

Graph of AC Voltage
("Sine Wave")



Most alternating voltages and current change level and direction over a smooth path, called a sinusoid (or "sine wave"), many times each second. The number of polarity changes per second is the frequency, and all U.S. utilities use the AC frequency 60 changes per second ("60 cycles" or "60 hertz"). This means that 60 times each second, voltage rises from zero to about +V (point A), then goes back to zero (point B), then goes negative to -V (point C), then rises to zero (point D). We don't notice that the voltage is changing because the changes occur too quickly.

If we replace the voltage generator in the circuit with an AC generator, the circuit looks almost the same (Figure 5B), but the graph of voltage and current versus time displays the familiar "sine wave" shape (at the bottom of Figure 5B). Here, at every instant, the current and the voltage obey Ohm's Law, V = I × R. The resistance doesn't change because it is a property of the circuit (the type of wire used, etc.). Ohm's Law says that when V is at its peak, I is also at its peak. A graph of voltage and current over time would show that they have simultaneous peaks and valleys.

This is where the plot thickens. Every electrical device, including simple wires, large transmission lines, generators, and every appliance you own, has two properties in addition to resistance. Like resistance, these properties depend on the physical construction of the device and on the materials with which it is made. These two properties are called *inductance* and *capacitance*. They are sometimes referred to as the two forms of *reactance*.

Every electrical component has all three of these properties in varying

[illegible] R and don't change it, but try [illegible]

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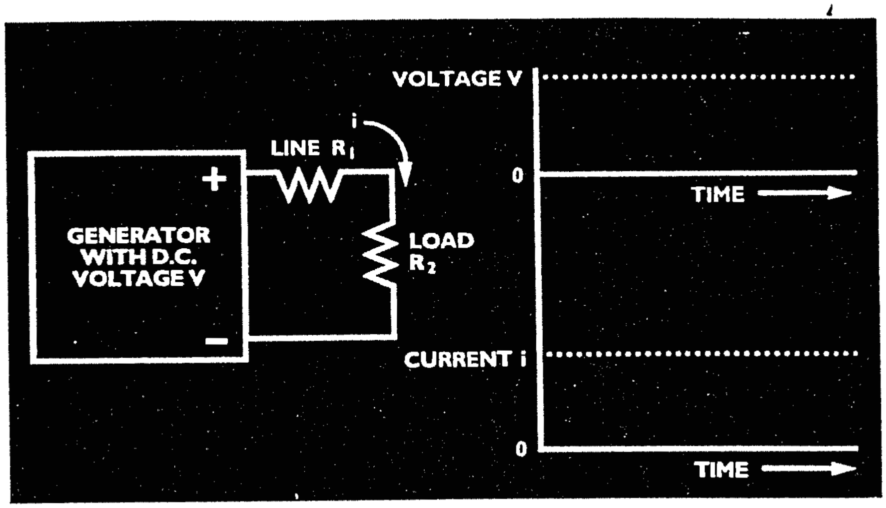
FIGURE 5A

"Realistic" Simple Electrical Circuit of Figure 1C with D.C. Voltage

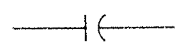


amounts. When the amounts of any two of the properties are very small, we call the device by its dominant characteristic. That is how we got away with calling the load in Figure 1C or 5A a resistor. Similarly, there are *inductors*, which are mostly inductive, and *capacitors*, which are mostly capacitive. In such cases, almost everyone ignores their other properties.

From the preceding it is obvious that the circuits in Figures 5A and 5B can never be purely resistive. However, inductance and capacitance have their main effects in AC circuits, so the circuit shown in Figure 5A is fine. If we want to be very accurate, it is a more correct way to draw the circuit in Figure 5B as shown in Figure 5C. Both the resistor and the transmission line have a little bit of inductance and capacitance, and this is shown by drawing their respective symbols:

Inductors

Capacitors
(which are also called condensers)



These symbols were chosen because one way to make an almost-pure inductor is to coil up some wire, and one way to make an almost-pure capacitor is to put two thin plates near each other but not touching. Engineers call the combination of resistance, capacitance, and inductance the *impedance* or *admittance* of a circuit.

FIGURE 5B

[illegible] Simple Electrical Circuit [illegible] AC Voltage

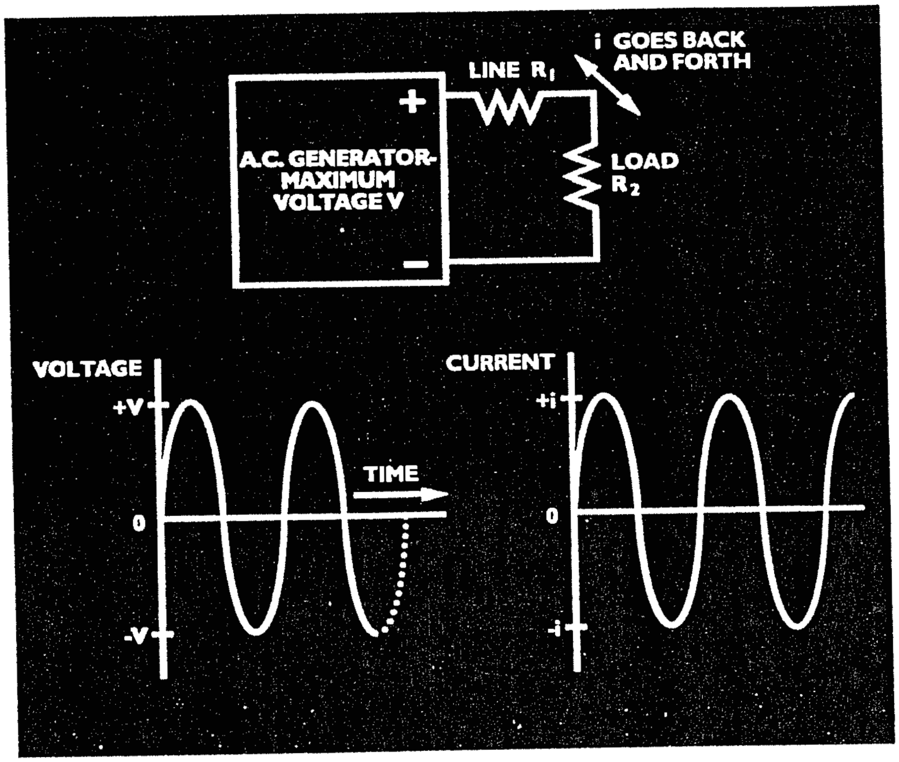
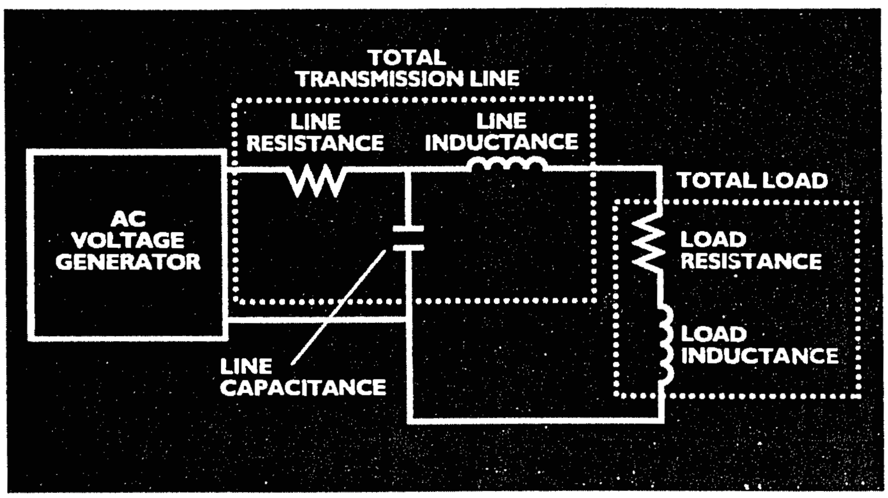


FIGURE 5C

Even More Realistic AC Circuit of Figure [illegible] Showing Resistive, Capacitive, and Inductive Circuit Elements



Real and Apparent Power

If and only if a circuit is AC rather than DC, under steady state conditions inductors and capacitors store electrical energy in a significant way. To understand this, return to the water-wheel circuit we examined in Chapter [illegible], Figure [illegible]A. In this circuit the water wheel was connected to the food grinder, and this was the circuit's load. Like most water wheels, this one is made of wood or metal, so it starts to move as soon as water flows. As soon as it moves, work is done. There is no energy storage in this circuit; the energy flow rate (power) in the pipe equals the work rate of the carrot chopper at the far end of the circuit. If the pressure moved back and forth periodically like the sine wave in Figure 5B, the water flow would follow in lockstep. This is the hydraulic equivalent of a pure resistive circuit.

Now imagine that the paddles of the water wheel are made of balloonlike rubber. The rubber is such that when water pressure hits the paddles, the balloons fill up until they are full. Only then will the paddle wheel turn. Figure 6A shows a picture of this hypothetical water wheel.

Now consider what will happen if the water pressure is quickly alternating back and forth. First the water flows in one direction and expands the balloon, but not enough to get the wheel moving (Figure 6B). Then the water reverses and the balloon deflates. Then, when the pressure is at its negative maximum, it expands in the other direction to hold the water.

This water-wheel circuit has the following strange properties:

FIGURE 6A

Water Wheel that Works Stores and Releases the Water Pressure

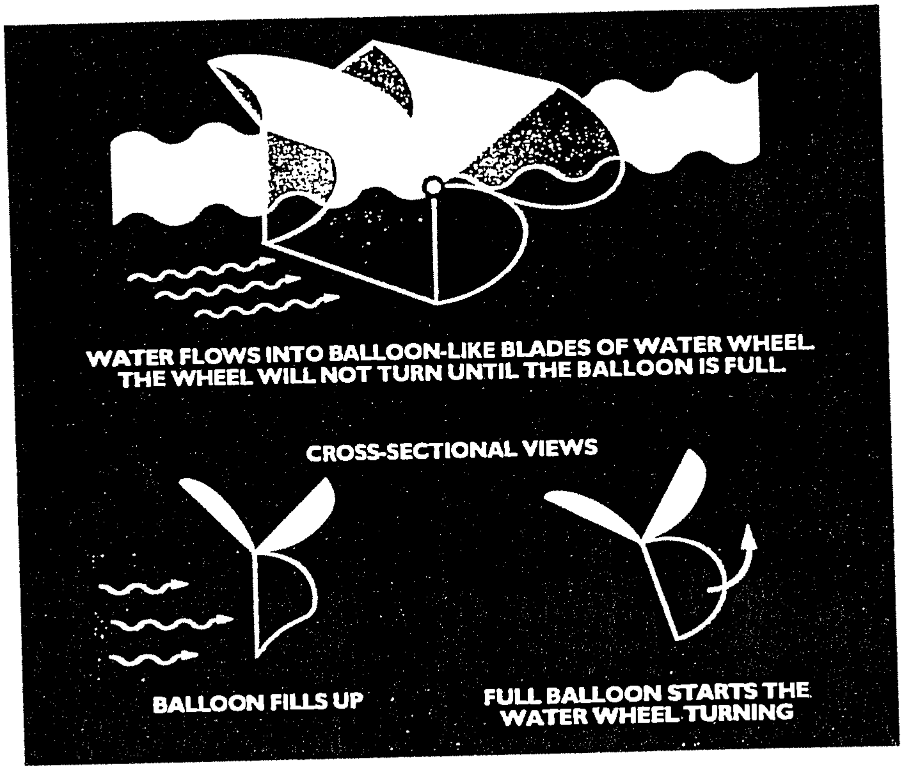


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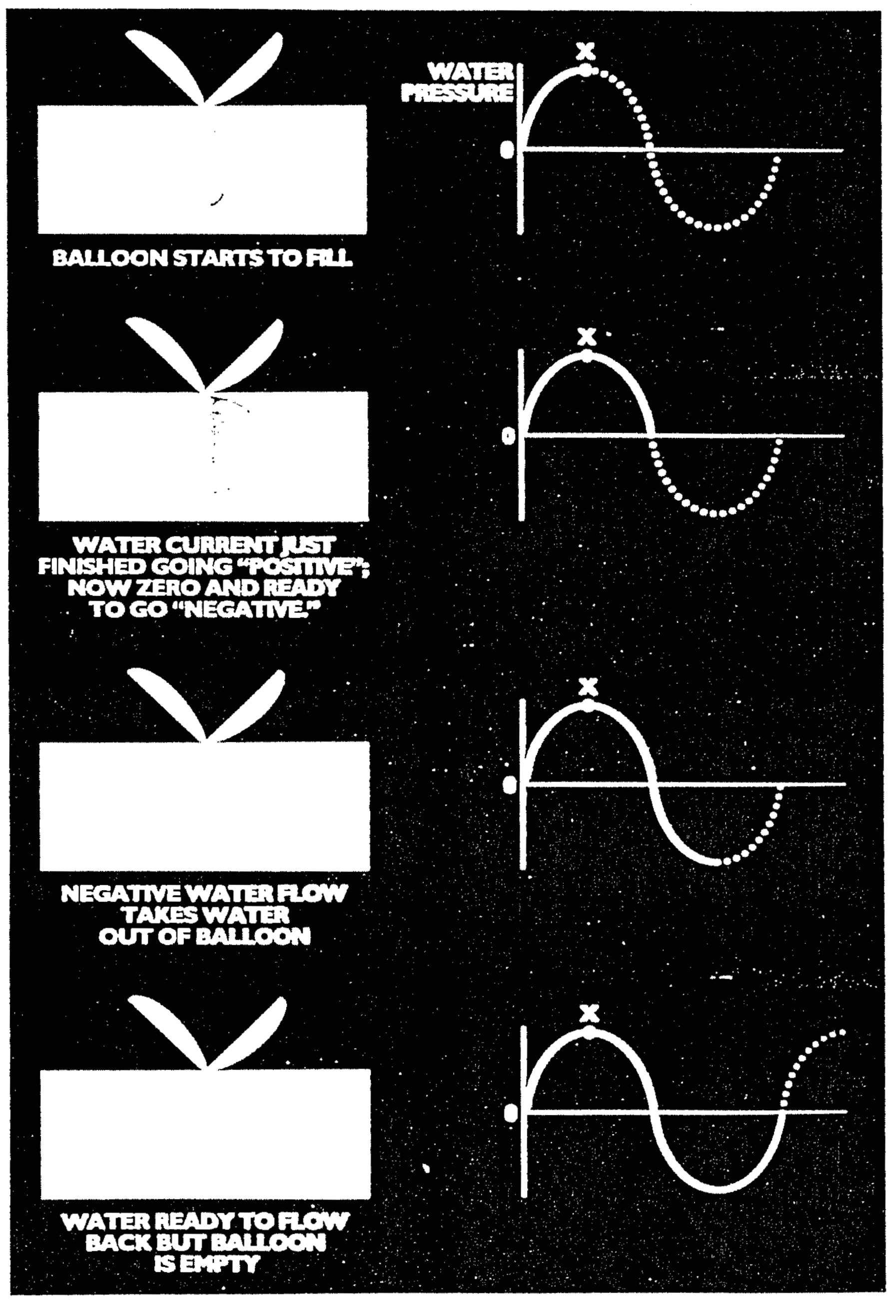
FIGURE 6B


WATER PRESSURE
X
0
BALLOON STARTS TO FILL
WATER CURRENT JUST FINISHED GOING "POSITIVE"; NOW ZERO AND READY TO GO "NEGATIVE."
NEGATIVE WATER FLOW TAKES WATER OUT OF BALLOON
WATER READY TO FLOW BACK BUT BALLOON IS EMPTY

1.The direction of the flow of water isn't exactly the direction of the pressure — there is a time lag between the two. This lag occurs because it takes time for the balloon to return to normal after pressure is removed in either direction. At the time when the positive pressure has peaked and started to decline, the balloon is still expanding (Point X in Figure 6B). At the time when the pressure changes from positive to zero to negative (i.e., when it changes its direction), the balloon is lagging behind, still absorbing water in the positive direction. If you were to graph the flow rate of the water and the pressure against time, the graphs would have the same shape but the water flow would *lag* the pressure.

2.The water wheel never moves, so no work is being done. But this is odd, because if you look at the pipe, there is both pressure and flow. According to the power equation, pressure times flow rate is power, so power is flowing in the pipe. According to conservation of energy, the power in the pipe cannot continue to flow into storage in the water wheel — it will be destroyed.

What is actually happening is a little tricky: power *is* flowing in the pipe, but it is flowing back and forth into storage in the water wheel. The wheel stores up energy for the first half of the cycle and ships it back on the second half. Because a complete cycle occurs many times each second, this storage/release process looks much like the *inductor* is storing the energy on an ongoing basis.

The electrical equivalent of this balloon water wheel is an *inductor*. In a purely inductive circuit (Figure 7A), the current lags the voltage by exactly one quarter of a cycle, just like the first balloon water wheel. Power flows back and forth over the transmission line, but no work is done. Instead of expressing the lag as a quarter cycle, it is customary to call one cycle 360 degrees and a quarter cycle 90 degrees. This is the same as calling an hour 60 minutes and a quarter hour 15 minutes. The number of degrees of lag between current and voltage is called the *phase difference* or the *phase angle*. The phase angle for an inductor is 90 degrees.

What would happen if we used rubber that was a little less pliable in the same circuit at the same pressure? In this case, the balloon paddles would fill up a little more quickly. If they filled while the pressure was still on in the same direction, the wheel would start to move in that direction (and therefore accomplish some work). If we were to graph the flow and pressure, the lag between current and voltage would not be a whole quarter cycle (90 degrees), it would be something less (Figure 7B). The actual work done in this circuit seems to depend on the flexibility of the rubber versus the force required to turn the wheel, and it seems to be correlated with the phase angle (lag).

The electrical equivalent of this circuit is the extremely realistic case of a circuit that has a load that is partly inductive and partly resistive. Remember we said that we can call loads resistors or inductors only if they are predominantly so; it is much more common to find loads that are somewhere between resistive and inductive. Almost all home appliances are like this, as well as motors, and fluorescent light ballasts. (Transformers, which

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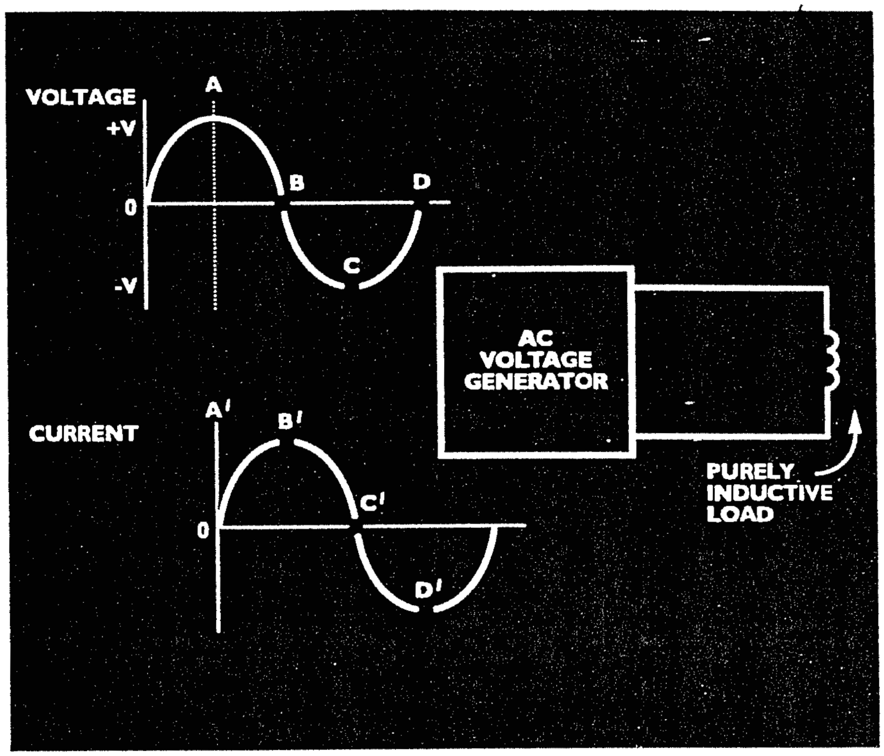
FIGURE 7A

[illegible]



[illegible]

[illegible]

[illegible]

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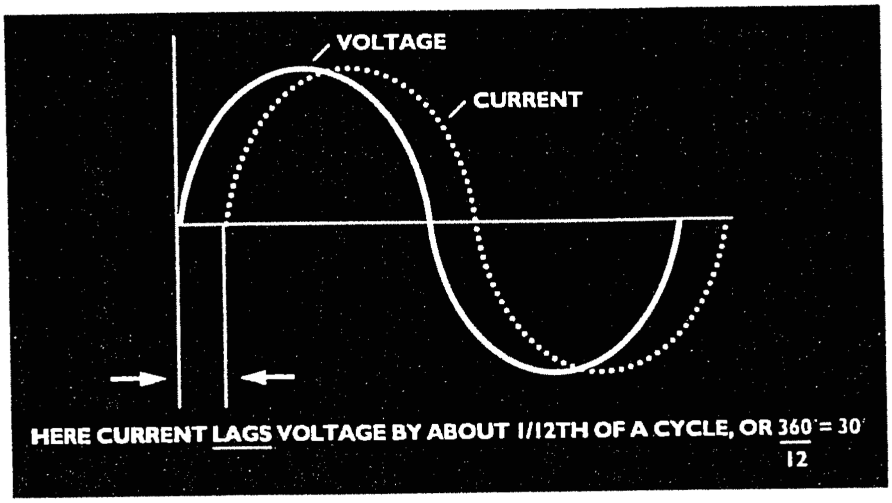
FIGURE 7B

A Partially Inductive Circuit Produces This Voltage-Current Relationship



volts times amps. In AC circuits, volts times amps is called *apparent power*. They also picked a good name for the kind of power that actually does work: real power. As in DC circuits, real power is measured in watts. Since both real and apparent power are both the product of volts times amps, watts are reserved for real power only and a transparent name was given to volts and amps that don't necessarily accomplish anything as they flow: *volt-amperes*, abbreviated VA.

If we are going to use the power formula to calculate both real and apparent power, a mathematical correction is needed to distinguish between the two. When we know that no work is being done, we want the formula to show it. We suspect the key to improving the formula is to use the phase angle between the voltage and the current. In the circuit shown in Figure 7A, the phase angle was 90 degrees (a quarter cycle) and no work was done. In the resistive circuit, the phase angle is zero and all power did work. The closer the phase angle to zero degrees, the more closely current follows voltage and the more the power is real, rather than apparent.

Incorporation of these ideas into the power equation is quite simple and uses the phase angle and the trigonometric cosine function:

Apparent Power = Volts × Amps
Real Power = Volts × Amps × Cosine θ

If the phase angle is 90 degrees, the value of the cosine function is zero (cosine 90° = 0). This is correct — the circuit is purely inductive, and there is

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no real power. If the circuit is resistive, the phase angle is zero, the cosine of zero is one, and the real and apparent power formulas are the same. This is why, when power was introduced in the first chapter, we didn't need the cosine term. In a DC circuit, the phase angle is always zero, and it was not necessary to use the cosine term.

Recall that we noted that virtually all circuits are partly inductive, in addition to being resistive. Cosine Θ is somewhere between zero and one. This means that apparent power is bigger than real power, which only makes sense. Apparent power is the product of *all* the volts and amps flowing whether or not they are doing work, whereas real power is only the portion doing work.

It seems as if we should to be able to subtract the real power from the apparent power to get the power not doing work.[24] If we do, we still get something that has the units of volts times amps, but it is neither apparent power, which usually has a partial work component, or real power, which is all work. To create a unit for *reactive power*, i.e., the flow of energy strictly affiliated with the purely reactive (inductive or capacitive) part of a circuit, engineers use a *volt-ampere reactive* or *VAR*. A VAR, commonly referred to by power engineers, is a unit of power that isn't doing any work but is flowing somewhere in a power system.

One final concept in this area is useful for understanding the lingo of power engineering. The term *power factor* (PF) is used to refer to value of cosine Θ in the apparent power function. It's nothing other than a number between zero and one that corresponds to the phase angle, which in turn corresponds to the difference between apparent and real power. A power factor near one means that current and voltage are "in synch" and most power is real; a power factor near zero means most power flow isn't doing any work.

Reactive Compensation in Power Systems

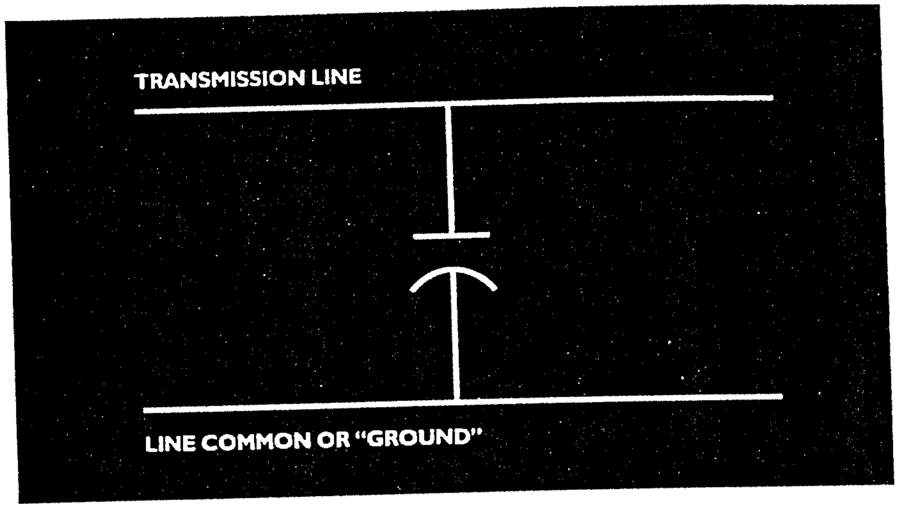
Even though it doesn't do any work, reactive power is of tremendous concern to power engineers. Recall that all power system components, and particularly generators and transmission lines, have maximum power limits. We have seen that transmission lines are limited by the heat caused by the current flow (i-squared-r losses), with losses going up rapidly with higher current. It doesn't matter whether the current is doing work at the other end of the line, because the line loss is caused by the purely resistive component of the transmission line. (The purely inductive component of the line also causes problems, but we'll get to them below.) The point is that if the **load** at the end of the line is partly inductive, the line will reach its capacity carrying currents out of phase with the voltage, which still cause losses and overloading.

For economic as well as technical reasons, it is preferable for both customers and utilities that all utility loads have phase angles that are small, or

Mathematically speaking, you do not actually subtract the two kinds of power. Instead, you use a trigonometric relationship.

FIGURE 8A

DIAGRAM OF A SHUNT CAPACITOR



A shunt capacitator is a capacitator connected between the transmission line and the common (or "ground") of the circuit. This type of correction tends to increase the phase differences that arise as power flows on the line.

recognize the kinds of capacitors utilities use to correct residential load factors. You'll find them at the top of the service poles not too far from your house.

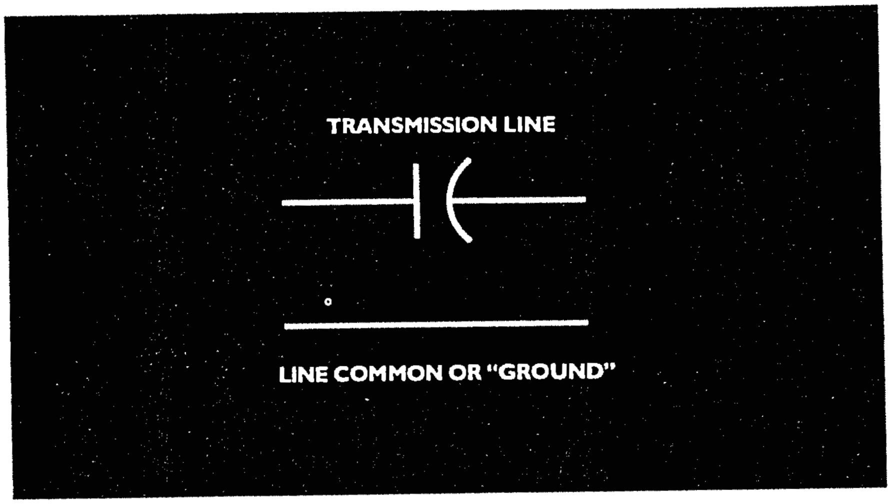
The inductive loads of customers are not the only power factor culprit in utility systems. We noted above that it is the resistive part of transmission lines that causes the line losses and makes customer VARs so wasteful. But the inductive part of lines causes the same problems for utilities as its inductive customer loads. After all, the inductive part of line A supplied by another line B and a generator will cause line B and the generator to waste energy supplying VARs to line A. So in some cases the utility needs to correct its own power factor at various points in the system inside the utility; this is called reactive compensation.

Reactive compensation can be accomplished in several ways. As just mentioned, adding capacitors is one way. Capacitors can be added in two basic ways to the circuit, called series and shunt. The basic circuit diagrams for these two types of physical connections are shown in Figures 8A and 8B, but for our purposes the differences aren't important.

The three other major methods of reactive compensation are shunt inductors, synchronous condensers, and static VAR systems. Shunt inductors are coils of wires connected like shunt capacitors. Synchronous condensers are basically rotating generator-like devices, and static VAR systems are complicated circuits with capacitors and inductors and large semiconductors.

FIGURE 8B

DIAGRAM OF A SERIES CAPACITOR



A series capacitor is a capacitor that is inserted into the transmission line so as to become a part of the transmission path. Series capacitors reduce the phase differences that arise during power transfers.

Reactive compensation is tricky because, even under normal (no contingency) conditions, the amount needed varies greatly with total system demand. This may seem to contradict the earlier statement that "inductiveness" is an inherent property of a circuit or device, and in a way it does. For simple devices like a coil of wire it doesn't vary, but for devices like motors and generators it varies substantially. Since motors are some of the biggest inductive loads, reactive compensation is an ongoing affair. Also, VARs must be provided near where they are needed. Correcting a power factor at one point on a system is not the same as correcting it at another point.

Reactive compensation adds yet another dimension to the responsibilities of power system planners and operators. In fact, for each of the design and operation requirements we discussed above for real power, there is a direct parallel requirement for reactive power. First comes adequacy, which [illegible] forecasting and design issue. Under normal operating conditions the transmission system should be capable of handling both the real and reactive power flows with compensation as needed. Next comes security. When doing loadflow calculations with many contingencies, the system must accommodate reactive as well as real power shifts. This is trickier than it was in the case of sudden shifts in real power, because sudden shifts in generator loadings change the inductiveness of generators, causing enormous changes in the energy they store. This can overload lines and damage [illegible] as real power cost. It is as if the value of the

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circuit components changes in a contingency, not just the geometry of the circuit.

As we saw in the case of real power, there is a continuum of reactive power responsibilities that stretches between the system planner and the operator. Recall that the area control center in the previous real-power-only discussion was constantly attempting to maximize economic dispatch, given the changing system security constraints. Now we see that the operator's computers must constantly monitor reactive as well as real power flows and check for possible contingencies that threaten the whole system. Sometimes the operator must turn on generators or adjust reactive compensation equipment out in the field just to prevent a threatening possibility from becoming reality.

Power engineers themselves have pushed the parallel between reactive and real power by calling reactive power activities that reduce costs or preserve security *reactive dispatch*. They often push the analogy still further by indicating that certain components "supply" VARs and others "consume" them. The idea of reactive dispatch is directly parallel to real dispatch, which seeks to balance supply and demand in the least expensive manner, provided the system remains adequate and secure.

Pushing reactive dispatch this far is a bit confusing, mainly because it is difficult to think about giving or taking VARs. Nevertheless, the idea is to think of inductive loads as requiring a certain number of VARs to operate. These VARs must be supplied either by the system's generators or by compensating equipment. What's confusing about this is that these two forms of VAR supply are quite different in terms of what they really do to the circuit. Capacitive compensation pulls current back toward voltage, whereas the actual supply of a VAR means providing some reactive power, i.e., making sure your system can deliver the reactive power as well as real power demands. However, the overall goal of the two kinds of dispatch is similar: both forms of power must be in balance in order to maintain voltage and supply demand, and the system must be protected against contingencies up to the level of reliability desired.

The Advantages of AC

With all the complications AC introduces to circuit behavior, some readers are probably wondering why almost all the utility systems of the world are AC rather than DC. An understanding of the advantages of AC will complete our overview of the technology of electric generation and wheeling.

AC brings with it several powerful advantages that make the problem of reactive dispatch well worth conquering. First, it is easier and cheaper to generate AC in large quantities, and it is convenient to be able to use the relationship between frequency and voltage as a means of control. The power flow itself carries the frequency and amplitude information necessary to control the system.

The second advantage of AC is very important. There is an electrical device almost everyone has heard of called a *transformer*. A transformer is

TABLE 3

TRANSMISSION AND DISTRIBUTION SYSTEM ELEMENTS AND THEIR VOLTAGES
(1 KILOVOLT OR KV = 1,000 VOLTS)

System Element	Voltage
Distribution Lines	11 Kv - 35 kV (p. 214)
Sub-transmission	35 kV - 230 kV (p. 199)
Extra-High Voltage (EHV) Transmission	230 kV - 800 kV (p. 182) (most common levels are 345, 500, 765 kV)
Ultra-High Voltage (UHV) Transmission	Above 800 kV (p. 123)

SOURCE: H.M. Rustbakke, ed., Electric Utility Systems and Practices (New York: John Wiley & Sons, 1983), 214, 199, 182, 123.

an inductive device for insertion into a power line that does not change real power flowing on the line, but trades off voltage and current. If voltage goes up, current goes down, and vice-versa, roughly preserving the real power product VIcos Θ.

This innovation makes it possible to reduce drastically the real power losses in transmission lines, because these losses are related to current rather than to voltage. The idea is to generate power at any voltage that's convenient, use a transformer to "step up" the voltage to the highest possible V (lowest possible I), and then, when the power is where you are going to use it, step it down to the voltage you want it to be. This doesn't change either of the fundamental system objectives/constraints: all power needed must be delivered and all voltages must stay constant. The only difference is that different parts of the system are now at different (but still inviolate) voltages.

In modern power systems, transforming is done in steps so as to minimize the total cost of transmission investments. Transformers are not free, and it is also more costly to build lines at higher voltages, though operating these lines is cheaper per unit of power delivered. Intuitively, these cost tradeoffs result in the use of higher voltages, the larger the power flow and the longer the distance.

Power engineers have given transmission systems in different voltage ranges the names transmission, sub-transmission, and distribution. The basic idea is that power is generated at several thousand volts, stepped up right at the power plant to several *hundred thousand* volts, and then stepped down at *substations* to sub-transmission voltages (below 138,000 volts) and then distribution. The voltage in homes is the very lowest the system gets, 120 volts, and i-squared-r losses are large enough at this level that utilities locate their last transformer right on the pole outside your house. Notice that a distribution substation is nothing more than a step-down transformer and lots of protective circuitry to monitor voltage and power on the transmission lines entering and leaving it.

Transmission systems are further classified into "ultra high voltage," "extra high voltage," and so on. Table 3 shows the range of names and voltages for AC transmission systems.

Finally, in spite of all the advantages of AC, it turns out that in some special parts of the country, too much power is flowing over long distances to permit proper dynamic stability (frequency and voltage control) and reactive compensation. In these areas, utilities have installed high-voltage DC transmission lines with circuits that change AC to DC at the sending end and DC back to AC at the receiving end. In today's utility industry, larger and larger amounts of power are traveling longer and longer distances, and DC lines may become somewhat more common than they are now.

Wheeling and Reactive Power

In our discussion of wheeling before we learned about reactive power, we saw that wheeling inside a control area was better described as the imposition of a load-flow constraint on the control area. The "costs" of wheeling included those incurred directly and indirectly as a result of the need to maintain a safe load flow everywhere in the control area. In wheeling transactions, reactive dispatch adds a new set of constraints and requirements that are similar in nature to real power.

The costs of meeting reactive constraints are even more difficult to conceptualize and measure than the constraints in an all-DC world. (In fact, the utility industry often doesn't even try to calculate the costs of reactive compensation for specific transactions.) If a utility's load-flow or stability studies indicate that a particular new investment is needed, and this need can be traced to a particular sale or wheeling transaction, the cost of this facility will probably accrue to the purchaser necessitating the investment.

POWER SYSTEM OPERATIONS IN REAL TIME

Introduction

Chapter 4 explained the ideas underlying the operation of power systems and the relationship between planning and operation. We learned that system planners study new generating plants and transmission lines by simulating the flows of power on the system and comparing the costs of system improvements to their ability to help the system supply at minimum costs. We also learned that system operators run the system from control centers to minimize the cost of supplying power from the existing system while at the same time acting to prevent line overloads or outages. We learned that when the levels of all generators are set so that even several sudden line or plant failures don't harm the system, we call this a secure dispatch. Finally, we learned that a new firm wheeling transaction essentially amounts to a constraint on the operation of the system. The control operator attempts to provide for economic and secure dispatch while additionally taking care that power is free to flow from buyer to seller.

In this chapter we revisit all of these ideas in a real-world context. We will learn more about how control centers actually operate and how they respond to wheeling transactions. We will also learn about power flows between control areas.

All of these activities occur in real time or on the basis of very short time horizons ranging from several seconds to 24 hours. This is the important time frame for those who operate the system because technical and economic problems on the system must be solved either immediately or in very short order.

Control of Electric Power Systems

Up until this time we have been acting as if the area control center has absolute and complete control over all generators and transmission lines in the control area. Actually, there is a hierarchy of control centers in all utility systems that span the generation, transmission, and distribution portions of the system.[25]

The Area Control Center, sometimes called the Company Dispatch Center, is the center of the control hierarchy, though not the top. This center has the primary moment-to-moment job of monitoring, dispatching, and controlling the generation and transmission system. Below this center are three types of subcenters (see Figure 9). Generating stations have their own control rooms, and they share the responsibility for controlling the plant with the area center. The transmission system typically has several control divisions with control operators in charge of each. Like generating station controllers, division operators share dispatch and control functions with central control, particularly focusing on preventive and emergency maintenance and local switching. Finally, the distribution system has a number of distribution dispatching centers with responsibilities analogous to their transmission system counterparts for the distribution substations in their area.

In many parts of the country, several utilities have banded together to form a "power pool." A pool is a multilateral contract under which utilities share their generating facilities and transmission systems. The idea behind a pool is to dispatch generating units so that lower cost generating units are used first, and more expensive units are added as customer demand warrants, without regard to who owns the units. Payments are made among the members of the pool depending on the proportion of each utility's generation that is used to meet overall customer demand, and the relative costs of that generation. Thus, savings of centralized, least-cost dispatch are shared among pool members. And pool members generally allow their transmission systems to be utilized for the benefit of all pool members.

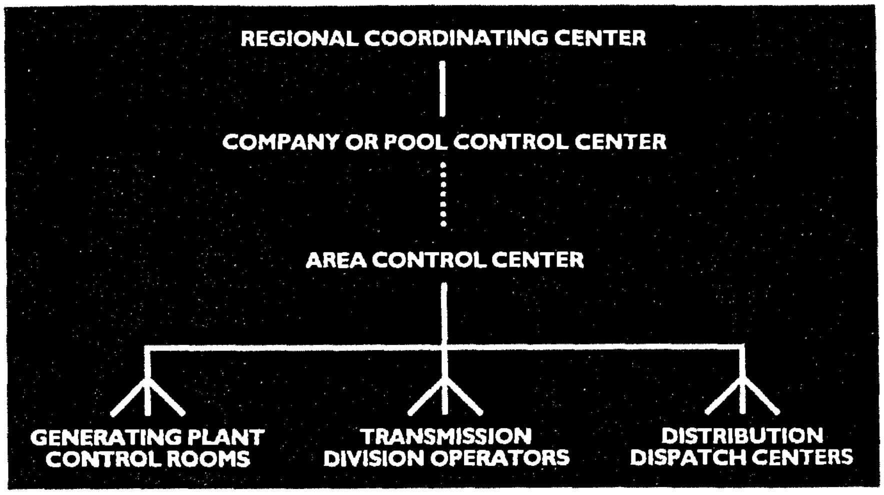
Planning and operating power pools is much like planning and operating an individual utility with many generators. The same ideas of economic dispatch apply, still constrained by the need to provide a secure dispatch, voltage and frequency constancy, transient stability, and so on. The difference is that the control job is much bigger and more complicated. Many more lines and units are involved, and the pool probably has numerous rules governing the sharing of resources, emergency procedures, planning and notification requirements, and so on. From the standpoint of hour-to-hour operation, however, there is probably a pool control center that oversees the activities of the area control centers of the utilities in the pool, and sometimes actually does a significant part of the operations tasks (which we willl examine in a moment).

With or without a pool control center, there is undoubtedly a regional control center that is the uppermost controller in hierarchy. In normal times, the regional center may only monitor conditions and act more as a planning

[25] This description of control center hierarchies is based largely on Rustbakke (1983) Chapter 4

FIGURE 9

HIERARCHY OF CONTROL IN
NORTH AMERICAN POWER SYSTEMS



body and operations coordinators, concentrating on long-term studies of regional expansion possibilities and emergency procedures. In large emergencies that threaten more than one utility system, however, these centers take over as communication and control centers. They give orders to the area or pool control centers, which in turn command all centers below them. This control hierarchy was established after the great New York City blackout of 1965, which revealed that a clear chain of command would help keep outages in one part of a system from affecting other areas.

Many of the controls on transmission lines and plants are automatic. Not only do they automatically shut down the line in case of an overload, they also can often adjust the electrical characteristic of the line as network conditions change. The changes made are a form of reactive compensation, which was discussed in the previous chapter, or in other words the addition of capacitance or other forms of VAR support at points where they are needed. All of this activity is monitored at the control center, which can intervene if it is necessary.

Control Center Activities

We have repeatedly emphasized the overlapping tasks and radically different time horizons used by the system planner and the system operator. As noted above, the latter confines his or her attention to the time between the next few minutes and tomorrow. The short-term activities of system operators are sometimes further divided into those occurring over a day (operations scheduling or operations planning) and immediate monitoring and control (*operations* or system *control*).

Operations planning consists of several activities that plan the operation of the system over the next one or two days. Operations planners look at the current level of power usage, the weather forecast, and other information and predict the amount of power that will be needed during each hour of the next day or week. They compile information on the operating costs of units, the near-term maintenance needs of plants and lines, requests for power purchases from neighboring utility systems, and other system considerations. With the help of economic and technical optimization programs, they produce a unit commitment schedule, or an advance assignment of generator use during the next 24-200 hours to provide continuing security at a minimum estimated cost.

The unit commitment schedule is the starting point for the activities of system controllers. They continuously monitor the system for contingencies and take action when they occur. Every five minutes (and sometimes continuously) they run computer programs that alert them to contingencies that will prove difficult to handle or that suggest other ways of improving the dispatch. When the unit commitment schedule calls for them to have an interchange with another utility or a wheeling transaction, they prepare for and execute the dispatch changes needed to effect the change.

Generation Control Methods

Although system operators have the ability to disconnect virtually any generator or transmission line in their area, they do not control the exact level of all their generators. As we learned in Chapter 4, "base-load" generators are designed with the capability to run all the time, while others run based on uncontrolled conditions such as the water flow in a river. The system is controlled by adjusting the outputs of the dispatchable plants and making nonautomatic adjustments on the transmission and distribution systems.

In the previous chapter we learned that the amount of power produced by a generator in an AC utility system was very closely related to the frequency of the generator. If all generators do not run at exactly the same speed, large system-threatening power transfers and system instability may result.

Control centers use the relationship between frequency and power transfer as the basis of their control. Currently dispatchable plants are placed on a system called Automatic Generation Control or AGC.[*] This system sends pulses to all dispatchable generators that cause the generator to speed up or slow down ever so slightly, pumping more or less power into the system. The system is controlled by a computer that can speed one unit up as it slows another down, enabling smooth power transfers to occur.

We know that the operator seeks to operate the AGC system to achieve economic dispatch within the constraints imposed by system security, required wheeling transfers, and so on. He or she already has an idea of

[*] The system is also called Load Frequency Control or LFC.

the lowest-cost secure dispatch from the operations schedulers. However, even a very good forecast of the best dispatch to use during the next few days will differ from actual dispatch due to differences between forecast and actual total load and the inevitable set of unplanned and unforecasted component failures. Also, it is difficult to forecast the amount of reactive compensation that will be needed and where it will be needed, and even more difficult to adjust the dispatch to insure that the system maintains stability in the event of a major outage. There are so many considerations to take into account that no one calculation or computer program can tell the operator what dispatch to use. Instead, the operator strives for security at least cost by continuously examining several computer calculations, monitoring the state of the network, and exercising judgment based on years of operating experience.

Interconnections and Wheeling Between Control Areas

All utilities and control areas have lines that lead into other utility service and control areas, often called *tie lines or interconnections.* The power exchanges that flow across interchanges represent transactions from a power-producing system (seller) to a power consumer (buyer). These may be "firm" transactions — fixed amounts of power sold continuously for many years — or transactions lasting only a few hours. In emergencies, tie lines are used to supply all of the power a system needs to maintain voltage (frequency) and stability. The important difference between these transactions and other power system activities is that these flows involve two control areas.

As we noted above, operations scheduling keeps track of scheduled interchanges and system controllers adjust the dispatchable plants using the AGC system. When an interchange is scheduled between two areas, controllers in the two areas change the settings on their AGC systems, so that the selling area exports the additional power called for in the transaction and the importing system absorbs the same amount.

The industry has developed a clever method of adjusting the plants in two or more control areas to provide for these interchanges. However, as we saw in Chapter 2, power flow in networks follows many paths according to Kirchoff's Laws, and we can't know the actual flow of power in networks with many lines and plants without a complicated, time-consuming load-flow calculation.

The interchange method developed by utilities avoids having to calculate load flows every time a sale is made by examining the total generation and total outflow of power from a control area. For example, if System A is generating 1,000 megawatts and all its tie lines indicated that 100 megawatts is being exported, then the system knows it is only using 900 megawatts. Similarly, System B may know that it is using 100 more megawatts than it is making, and all other systems know the same. If an interchange calls for System A to sell 100 more megawatts to System B, then these systems adjust their AGC controls together until their total generation and tie line flows give the proper value.

What happens to the rest of the systems interconnected to A and B when these two adjust their AGC to effect an interchange? At the end of the transaction, we know that Systems A and B have the right *net* interchange, but we also know that some of the power is undoubtedly flowing through other systems. If all other systems adjust their AGC so that they have the same net interchange as before the transaction, then only Systems A and B have changed their net sale and purchase. So in total the system now is exactly where it was before the transaction, except for the change in the transaction.

Power flows caused in systems that are not parties to an interchange have come to be called *loop flows*. Because it is difficult to know exactly where the power flows (at a minimum, you have to run a simulation), it is often difficult to tell how much adjustment Systems C, D, etc. have to make for each particular transaction between A and B. If the adjustments aren't large, sometimes the systems just ignore them, but if they are large and costly Systems A and B sometimes pay the other systems affected by the transactions.

But something is a little funny here! Systems A and B have adjusted their net interchange so that one is buying and the other selling the correct net amount. If all other systems have adjusted to return to where they were originally, why should A and B have to compensate the others? In other words, what does the adjustment of the third-party systems really represent if they are simply returning to their original net interchange?

The adjustment of the third-party systems is by definition the adjustment they must make to account for the "loop flows" going through their systems as a result of the change in A-B interchange. The new shipment of power from A to B changes the equilibrium load flow over a wide area of the network; its effects do not stop at the boundaries of the systems defined as control areas. When the A-B transaction starts to change flows in C, the operator in control area C must change the system to create the new economically optimal secure dispatch. Depending on conditions inside his or her system and conditions in other systems at that exact time, the new flows stemming from the A-B transaction will require a new optimal dispatch that is higher or lower in cost than the previous secure dispatch. One of the reasons why third-party compensation is difficult is that, due to the number of transactions occurring simultaneously, it is often hard to tell what changes in the costs of running other systems are caused by a particular transaction, or even whether the effects are large, small, positive or negative.[*] If the third-party costs of a particular transaction can be measured and demonstrated, the affected third party often will request compensation.

The reader will recall that the wheeling transaction we examined in Chapter 4 is almost the same transaction as the example of interchange between A and B we have been looking at in this chapter. In both cases, the system has to be controlled and adjusted to make sure that a total amount of power emanates from one location as is available at another. Why

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It is possible that changes in net flows helps a system reduce its total operating costs. For example, a new flow could reduce the loading on a line, which reduces the losses or the need for reactive compensation.

weren't we concerned with loop flows inside the control area in Chapter 4? The answer is that we were, but we didn't use the term loop flows because we were only looking at one control area. Inside one control area, a wheeling transaction between one generator and one load causes all sorts of loop flows inside the area. As we said in Chapter 4, it introduces a constraint to the dispatchers that may cause them to adjust the entire dispatch of the system, change reactive compensation, or otherwise change the total system costs towards or away from the pre-existing least-cost dispatch. We didn't call the network flow changes loop flows because they were all inside one area, and we limited our analysis of the total cost impacts of the wheeling transaction to those inside the area. Though the calculation and compensation scheme becomes more complex when several control areas have flow changes, the idea is the same.

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SUMMARY AND CONCLUSIONS

The purpose of this primer has been to introduce nontechnical readers to the concepts and terms needed to understand electric power systems, transmission and wheeling. This has involved introducing you to the basics of electricity and power system design and operation. To review, we have learned the following:

1. The purpose of a power system is to deliver real power at a constant voltage. We have adopted a technical and regulatory model for our electric system that permits the customer to choose the amount of electric energy demanded. Although this model is evolving, utilities continue to have the obligation to *plan* and *operate* a system that always maintains a constant voltage and delivers all energy demanded, within certain limits.

2. Real power flows in a transmission system according to natural laws, and it is not possible to strictly match individual suppliers of power with individual loads. Moreover, the transmission system must have redundancy because transmission lines are always in danger of breaking. When a line breaks, the flows rearrange themselves.

3. The job of the utility system planner is to design and operate the system for least-cost operation under normal conditions (adequacy) and also for continued service under contingencies (security). To do this, planners use *load-flow models* and *stability studies*. Proper planning occurs over a long time horizon because it takes several years to build new facilities, and these investments last for decades. Planners use several types of optimization and planning models to try and foresee the amount of power needed in the future and the lowest-cost investments capable of providing future [illegible] demands under the technical conditions needed to maintain reliability.