PN-ACD782

ENERGY TRAINING PROGRAM

Economic Management of a Distribution Company

August 25- September 5, 1997

in

Manila, Philippines

Sponsored by:

Department of Energy

Republic of the Philippines

USAID Mission in Manila

and

USAID Center for Environment

Designed and Implemented by:

EDS Utilities

and

Institute of International Education

Volume I

PN-HCD-782

ECONOMIC MANAGEMENT OF A DISTRIBUTION COMPANY

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PROGRAM SUMMARY

Background of the Philippines' Power Sector

The current (1996) installed capacity is about 10,556 MW which includes 2,333 MW hydro, 1,414 MW geothermal, 1,460 MW coal and 5 349 MW oil To meet the growing demand for electricity, an additional capacity of 12,978 MW will be installed between 1996 and 2005, bringing the total nationwide installed capacity to 23,264 MW

The demand for electricity is projected to increase at an annual average of 12 per cent between 1996 and the year 2005 This translates into an increase in power demand from 5 855 MW in 1996 to 16,256 MW in 2005 Correspondingly, electricity sales are expected to increase to 93,313 GWhr in 2005 from 33,532 GWhr in 1996

With the implementation of energy conservation and demand-side management (DSM) programs, a significant reduction in energy consumption is projected A decline in the annual growth of electricity demand by an average of about 5 4 per cent shall be affected by the impact of energy efficiency and DSM programs

The need for reform of the Philippines' power sector came about by the power crisis of the early 1990's when it began experiencing brownouts of two hours per day By the summer of 1993, the daily brownouts had reached eight to ten hours a day, thereby crippling the economic activities The national government and the National Power Corporation responded to the crisis by initiating and involving the private sector in financing, building and operating power plants The successful experience of this initiative resulted in the Department of Energy's (DOE) comprehensive power sector structural reform of 1996 to rationalize the power sector The main objectives of these reforms are

- to create an environment which permits and encourages sufficient investment to meet expected expansion of the power sector,
- to develop a competitive environment that will encourage efficiency and reliability in production and delivery of electricity to consumers at a reasonable price, and
- to establish a regulatory and policy structure that will protect the consumers, while maintaining the ability of the sector to finance necessary expansion projects by allowing participants to operate commercially

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Under the proposed restructuring, DOE plans for the unbundling of the NPC into a series of Generation Companies (Gencos) and a regulated Transmission Company (Transco) The generation subsector, including new generation companies and existing Independent Power Producer (IPP) generation, will be responsible for power generation in a market-based, highly competitive environment The Transmission Company will be responsible for operation and dispatch on a real time basis that will meet demand on a least cost basis, while maintaining system reliability The responsibility of providing power will be delegated to Distribution Companies (Discos) The Energy Regulatory Board (ERB) will be responsible for (1) setting and enforcing performance standards for Gencos based on reliability and efficiency to ensure fair and high competition between these Gencos, (2) regulating transmission service pricing and transmission system operations, and (3) setting and enforcing performance standards for distribution utilities, including financial management, based on reliability and system efficiency to ensure the lowest possible cost to consumers

ASEI Philippines Energy Training Program

The Asia Sustainable Energy Initiative (ASEI), developed under the Global Climate Change for the Philippines, Indonesia and India mandate, is set of activities to address the major obstacles to large-scale implementation of commercial sustainable energy project development schemes by focusing on policy and regulatory reform, planning and project development In the case of the Philippines, understanding that the power sector is experiencing growth in demand for electricity, at the same time, undergoing a transition from state-owned power companies to an unbundled and competitive power industry, USAID/Mission in Manila directed the Energy Training Program (ETP) to develop the ASEI training component to support the Government of the Philippines' (GOP) plan of restructuring, regulatory reform, and privatization Providing training in support of a restructuring effort is expected to result in a market-oriented electricity sector, which will enable the adaptation of renewable energy and energy efficiency projects

Under ASEI Philippines, ETP is implementing the following courses in support of the GOP's training priorities

Power Sector Regulation	April 7-11 (1 week)
Tariff Structure and Rate Making	May 19-23 (1 week)
Environmental Management of Thermal Power Plants	July 21-August 1 (2 weeks)
Economic Management of a Distribution Company (Disco) - focus on IRP	August 25-September 5 (2 weeks)
Transmission Access, Power Wheeling and Economic Dispatch	Sept 8-12 (1 week)

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U S AGENCY FOR INTERNATIONAL DEVELOPMENT

INSTITUTE OF INTERNATIONAL EDUCATION

ENERGY TRAINING PROGRAM

THE ENERGY TRAINING PROGRAM (ETP)

The Energy Training Program (ETP) of the United States Agency for International Development (USAID) trains energy and environmental professionals from A I D -assisted countries (AACs) in how best to assess, utilize, and manage their energy resources ETP supports the program plans and activities of USAID's Center for Environment, the regional Bureaus and the overseas Missions

The Institute of International Education (IIE) manages ETP ETP works with AACs' energy and environmental sectors to assess their capabilities and identify training needs In response to their needs, the program develops courses in conjunction with the U S energy and environmental industry ETP ensures that participants receive practical, skills-oriented training in every program and access to modern technologies, methodologies, and management techniques Its staff closely monitor each training program to guarantee excellence

ETP covers the full range of conventional and alternative energy options available to AACs, with an emphasis on energy efficiency, environment, renewable energy, and privatization ETP has developed a two-pronged approach to training the Management-Level Training Program (MTP) and U S -based courses The MTP provides short-term, in-country workshops for senior management and policy makers These workshops are designed to increase understanding and build support for energy and environmental issues among key decision-makers The U S -based courses provide more in-depth, practical training This integrated approach is designed to strengthen the institutional capacity to plan and implement sustainable energy projects

To further enhance the effectiveness of training, ETP has established an Alumni Network, uniting its over 5,000 graduates The Network is served by the *ETP Digest, a newsletter which provides information on individual alumni accomplishments and upcoming training opportunities*

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USAID's CENTER FOR ENVIRONMENT

The U S Agency for International Development (USAID) allocates a significant portion of its assistance efforts to the wise management of environment and natural resources USAID has further underscored the importance of environmental issues by creating the Center for Environment The Center's mandate is to provide technical and programmatic leadership and support to the Agency and its domestic and international development partners in addressing global environment and sustainable development problems

Specifically, the Center provides technical support to USAID field missions and regional bureaus, identifies and analyzes critical environmental problems and the constraints to their resolution, guides Agency strategy in specific environmental areas such s global climate change and biodiversity, helps to ensure consistent excellence in technical capabilities and Agency programs, and synthesizes and disseminates data from technical and scientific research

The Center for Environment also collaborates with a wide range of partners -- host countries, non-governmental organizations, other U S government agencies, international organizations, and other donor countries -- to solve environmental problems on local, regional and global levels

INSTITUTE OF INTERNATIONAL EDUCATION (IIE)

IIE is the largest privately-operated, international education and training agency in the United States Since 1919, IIE has promoted international understanding and furthered international development IIE currently administers over 270 programs for government and private sponsors worldwide The Energy Training Program, under which this course in Economic Management of a Distribution Company training program falls, is sponsored by the Office of Energy, Environment and Technology of the United States Agency for International Development (USAID)

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U S AGENCY FOR INTERNATIONAL DEVELOPMENT

INSTITUTE OF INTERNATIONAL EDUCATION

ENERGY TRAINING PROGRAM

Economic Management of a Distribution Company

August 25 - September 5, 1997
Manila, Philippines

Course Objective

The objective of this workshop is to equip managers and staff of electricity distribution utilities with conceptual and analytical skills in finance, business, planning, and operation of a distribution company The goal is to prepare the participants in operating under a restructured and competitive electricity market

Who Should Attend

This course is designed for managers of distribution utilities responsible for economic and finance management of the company, senior planners of the distribution company, officials of the Department of Energy (DOE), Energy Regulatory Board (ERB), and National Electrification Authority (NEA) responsible for overseeing the activities of the distribution sector

Course Goals

The main goals of the program are directed toward developing on the part of attendees a general understanding of

- Economic concepts of utility operation
- Public utility rate making including the determination of revenue requirements, cost analysis and rate design
- Alternatives to utility service disconnection
- Utilities planning processes
- Management and financial information systems
- The organizational and business process framework within which distribution companies operate
- The utility value chain
- Support processes
- Performance measurement
- Key information technology

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Course Outline and Schedule

I DISCO Financial and Business Management *(Week 1)*

Monday, August 25

8 30 - 10 00 Welcome Remarks and Opening Statement *DOE, USAID and IIE*
10 00 - 10 15 Team Introduction *EDS*
10 15 - 10 30 Coffee Break
10 30 - 12 00 Economic Principles *Dr Youssef Hegazy*
- Introduction Industry structure and restructure around the World
- Principles of Rate Design
- Determining Revenue Requirements
- Traditional Rate Structures

12 00 - 1 00 Lunch
1 00 - 2 45 Introduction to Specific Rate and Regulatory concepts *Dr David Boyd*
- Cost-of-Service Studies
- Performance - based Regulation

2 45 - 3 00 Coffee Break
3 00 - 5 00 Introduction to Specific Rate and Regulatory concepts *(continued)*
- Price and revenue caps
- Problems presented by common costs
- Periodic review of industry behavior

Tuesday, August 26

8 30 - 9 45 Introduction to Specific Rate and Regulatory concepts *Dr David Boyd*
- Sample cost allocation methods
- Problems presented by cross-subsidy

9 45 - 10 00 Coffee Break
10 00 - 12 00 Demand-side Management and Conservation
12 00 - 1 00 Lunch
1 00 - 2 45 Alternatives to Utility Service Disconnection *Dr Youssef Hegazy*
- Concerns of affordability and availability
- Achieving an appropriate fairness V s efficiency tradeoff
- Disconnection moratoria and restriction policies

2 45 - 3 00 Coffee Break
3 00 - 5 00 Alternatives to Utility Service Disconnection *Dr Youssef Hegazy*
- Billing and pricing arrangements
- Non-price, preventive, customer service programs
- Smart Cards
- Evaluation of USA utilities experience with alternative programs

Wednesday, August 27 *Dr David Boyd*

8 30 - 9 45 Business Process
- Business Environment
- Business Structures

Organizational Model
Business Process Model

12 00- 1 00 Lunch

1 00 - 2 45 Planning Process
- Corporate
  - Environment and company capabilities
  - Strategic plan
  - Overall operating and financial plan
  - Planning and budgeting instructions

2 45 - 3 00 Coffee Break

3 00 - 5 00 Planning Process *(continued)*
- Corporate *(continued)*
  - Consolidation of area budgets
  - Regulatory impacts
- Individual
  - Functional action plan
  - Responsibility area budgets

Thursday, August 28 *Dr David Boyd*

8 30 - 9 45 Planning Models *continued*
- Distribution System Expansion Plan
- Load Forecast
- End Use
- DSM

9 45 - 10 00 Break

1 00 - 12 00 Planning Models *continued*
- Rate and Revenue
- Budgeting
- Financial
  - Pro forma financial statements
  - Financing plan
  - Ratios and other factors
  - Economic forecast

12 00 - 1 00 Lunch

1 00 - 2 45 Activity-Based Management Overview
- Relevant and targeted information
- Cross functional v s Discrete departmental work
- Financial management system
- Work/project management systems

2 45 - 3 00 Break

3 00 - 5 00 Performance Measurement
- Unit Cost Reporting
- Productivity Reporting

Friday, August 29 *Dr Youssef Hegazy*

Planning Model Workshop - Cost of Service Case Study

8 30 - 9 45	Strategic Planning Model Introduction to PORSCREEN II Financial Planning and Reporting Model (FIR), Class Revenue Model (CRM)	
94 5 - 10 00	Break	
10 00 - 12 00	Cost of Service Analysis	
12 00 - 1 00	Lunch	
1 00 - 2 45	Cost of Service Analysis Case Study	
2 45 - 3 00	Break	
3 00 - 5 00	General Discussion	

II DISCO OPERATIONS MANAGEMENT *(Week 2)*

Monday, September 1

8 30 - 9 30	Introduction and Overview of Background	*Dr Youssef Hegazy*
9 30 - 10 15	External Impacts on a Distribution Company	*Mr Billy Ussery*
10 15 - 10 30	Coffee Break	
10 30 - 12 00	External Impacts on a Distribution Company *(cont'd)* External Suppliers External Influences External Clients Other External Forces	*Mr Billy Ussery*
12 00 - 1 00	Lunch	
1 00 - 2 45	Establishment of Customer Focused Service *(cont'd)* Metering Billing Collections Customer Needs/Demands	*Mr Billy Ussery*
2 45 - 3 00	Break	
3 00 - 5 00	Establishment of Customer Focused Service	*Mr Billy Ussery*

Tuesday, September 2 *Mr Billy Ussery*

8 30 - 10 15	Distribution Company Support Services Human Resources Information Services Buildings and Grounds Fleet Management	
10 15 - 10 30	Break	
10 30 - 12 00	Distribution Operations Engineering Field Operations General Operations and Maintenance System Planning	
12 00 - 1 00	Lunch	

1 00 - 2 00 Financial Planning
Finance and Accounting
Rate Making
Planning and Budgeting
2 00 - 3 00 Materials Purchasing and Management
3 00 - 3 15 Break
3 15 - 4 00 Governmental Relations
4 00 - 5 00 Audit/Legal/Corporate Communications

Wednesday, September 3 *Mr Billy Ussery*
8 00 - 9 00 Activity Based Management Overview
9 00 - 10 15 Process Related Data Capture
10 15 - 10 30 Break
10 30 - 12 00 Unit Cost Reporting
12 00 - 1 00 Lunch
1 00 - 3 00 Performance Measurement
3 00 - 3 15 Break
3 15 - 4 00 Productivity Reporting
4 00 - 5 00 Project Bench marking

Thursday, September 4 *Mr Billy Ussery*
8 00 - 10 00 Customer Information
Information
Accounting
Billing
Consolidated Bills
Late Pay and Arranged Payments
10 00 - 10 15 Break
10 15 - 11 00 Marketing
11 00 - 12 00 Work Management
12 00 - 1 00 Lunch
1 00 - 2 45 Automated Systems
Meter Reading
Outage Notification
2 45 - 3 00 Break
3 00 - 4 00 Information Technologies
Electronic Bulletin Boards
Remote Access to Customer Data
Internet Access
4 00 - 5 00 Power Marketing
Pros and Cons

Friday, September 5 *Mr Billy Ussery*
8 00 - 9 00 SCADA
Overall Plan

	Distribution Automation
	Load Management
9 00 - 10 00	GIS / AM-FM Systems
10 00 -10 15	Break
10 15 - 11 00	Materials Management
11 00 - 12 00	Communications
12 00 - 1 00	Lunch
1 00 - 2 45	Other Support Systems
	New Technologies
2 45 - 3 00	Break
3 00 - 5 00	Wrap Up and General Discussion
	Closing and Graduation

BIOGRAPHIES OF COURSE INSTRUCTORS

David M. Boyd, Ph.D.

Dr Boyd is currently employed by EDS Utilities Division He has more than 20 years experience in the utilities and energy sectors In addition to tenure at consulting and research firms, he was employed by a major utility for twelve years directing and performing planning and operational studies His experience includes strategic assessments, process and information planning, quantitative studies, resource planning, and energy policy analysis He has provided direction through membership and leadership of several industry committees in the energy research community and in the utility planning area

Dr Boyd's expertise lies in Business Process Reengineering, Regulatory and Policy Analysis, Business Information Planning, Rate and Economic Analysis, Strategic Planning, Demand-Side Planning, Strategic Marketing and Research, and End-Use Forecasting and Analysis His experience in the areas of Business Process Reegineering and Information Planning include developing a Strategic Application Architecture Direction for Tucson Electric Power, reengineering and information planning for two gas utilities in the Czech Republic, reengineering the market activities of the Southern Company, enterprise reengineering engagement for a utility in the Netherlands, developing design elements for a marketing information system, and developing resource allocation methodology for Brooklyn Union Gas Company In the area of strategic planning, he planned and led seminars and workshops for executive management that focused on the changing business environment for utilities for the Southern Company, assessed alternative business scenarios and tracked the restructuring of the utility industry for the Southern Company, and identified opportunities available for the Turkish Electric Authority in Turkey

As a strategic marketing and researcher, Dr Boyd managed the market planning at Southern Company Services, developed strategic marketing plan for the Southern Company, performed market research on large industrial clients of the Southern Company, and developed a 5-year retail marketing and sales plan for Georgia Power In the areas of regulatory and policy analysis, he wrote testimony on Georgia Power's DSM Plan, assessed external methodologies for Georgia Power Company, assessed the National Energy Policy Act of 1992 for the Southern Company, analyzed U S federal energy policies on energy technologies, and researched energy efficiency options for the Canadian Ministry of Energy As a rate and economic analyst, he assessed rate impact of DSM for the Southern Company, developed a training on cost-benefit analysis for staff engineers from international and U S utilities (including Japan, Canada and Turkey), performed economic assessment of electric end-use technology for the Southern Company, and conducted quantitative studies on end-use conservation and energy efficiency opportunities for 17 states in the southern U S , Puerto Rico, and the U S Virgin Islands Finally, in the area of end-use forecasting and analysis, Dr Boyd advised the Electric Power Research Institute (EPRI), developed, installed and calibrated an end-use forecasting and analysis system for the Gulf Power Company and the Mississippi Power Company

Prior to working at EDS, Dr Boyd worked for the Southern Company, Southern Solar Energy Center, The MITRE Corporation, and Ketron, Inc He earned both a Ph D and M S in mathematics from the University of Carolina at Chapel Hill He has authored more than thirty

reports and published articles on utility planning, marketing, end-use forecasting, operations research, complex analysis and functional analysis He has given numerous presentations at conferences and at colleges on strategic marketing, business planning, economic analysis, DSM, and conservation and renewable technologies

Youssef Hegazy, Ph.D

Dr Hegazy is a senior consultant with EDS Utilities Division's Corporate Planning Group He provides consulting services to utility U S and international clients His specialties include competitive market assessment and utility de-regulation Since joining EDS, he has performed on-site consulting for various clients, including market evaluation of transmission investments, Integrated Resource Planning (IRP), avoided cost and cost allocation analysis, optimal reliability and reserve margin studies, business and financial analysis, and system and financial data development Dr Hegazy recently provided consulting to Egypt's Public Utility Sectors regarding proposed regulatory structures

His other areas of expertise include economic and regulatory analysis, production cost simulation and reliability analysis, IRP, DSM evaluation, outage cost analysis, avoided cost analysis, alternative pricing and incentive regulation, load research and load forecasting, system and financial analysis and data development

Prior to joining EDS, Dr Hegazy was a senior Research Associate with the National Regulatory Research Institute (NRRI) at Ohio State University At NRRI, he carried out research studies related to the regulatory, economic, and planning structure of the electric and gas industries

He received his Ph D in City and Regional Planning from Ohio State University (Dissertation Reliability-Based Pricing of Electricity Service), his M Sc in Energy Management and Policy from the University of Pennsylvania, and his B Sc in nuclear engineering from the University of Alexandria in Egypt He has published articles in load flow techniques, electricity reliability, DSM programs, fuel-related incentives, retail wheeling, and power market analysis

William Fred Ussery

Mr Ussery is currently the manager of engineering for Sawnee Electric Membership Corporation (EMC) located in Cumming, Georgia This electric cooperative is ranked in the top twenty in the nation in overall size and is also ranked within the top five fastest growing in the U S Current growth rates are in excess of 10% annually Such rampant growth dictates maintaining a constantly growing distribution system, while attempting to also manage construction cost and scheduling

The most recent challenge relates not only to Sawnee EMC but to cooperatives and other power companies in general The threat of deregulation of the electric utility industry from both a state and national level is ever in the forefront This increases the threat of public concern over rate disparity (currently over 15%) within the current service areas Primary focuses continue to be delivering high levels of customer service at the very lowest possible cost It is necessary to

constantly review methods, procedures and technology in search of more efficient and effective ways to produce reliable and economical electric service

Mr Ussery's responsibilities within Swanee EMC include management of the following sections Planning, Mapping, Buildings and Grounds, Warehousing and Purchasing, Engineering, Distribution analysis and design, power quality, general rate analysis and utility consumer relations

He received a bachelor's degree in electrical engineering from Auburn University and an Associate of Science degree from Middle Georgia College He is a member of the Institute of Electrical and Electronics Engineers, the Power Engineering Society and the Georgia EMC Engineering Association

EDS

Seminar Agenda
1ST WEEK
"Economic Management of a Distribution Company (DISCO)" Workshop

I DISCO Financial and Business Management
(Dr David Boyd and Dr Youssef Hegazy)

Day 1

8 30 - 10 00 **Welcome Remarks and Opening Statement** (USAID and IIE)

10 00 - 10 15 **Team Introduction** (EDS)

10 15 - 10 30 Coffee Break

10 30 - 12 00 **Economic Principles** (Dr Youssef Hegazy)

- Introduction Industry structure and restructure around the World
- Principles of Rate Design
- Determining Revenue Requirements
- Traditional Rate Structures

12 00 - 1 00 Lunch

1 00 - 2 45 **Introduction to specific Rate and Regulatory concepts**
(Dr David Boyd)

- Cost-of-Service Studies
- Performance - based Regulation

2 45 - 3 00 Coffee Break

3 00 - 5 00

- Price and revenue caps
- Problems presented by common costs
- Periodic review of industry behavior

Economic Principles of Pricing and Rate Design

USAID/IIE WORKSHOP

Economic Management Of a Distribution Companies

MANILA, PHILIPPINES,

August 25 - September 5, 1997

TOPICS

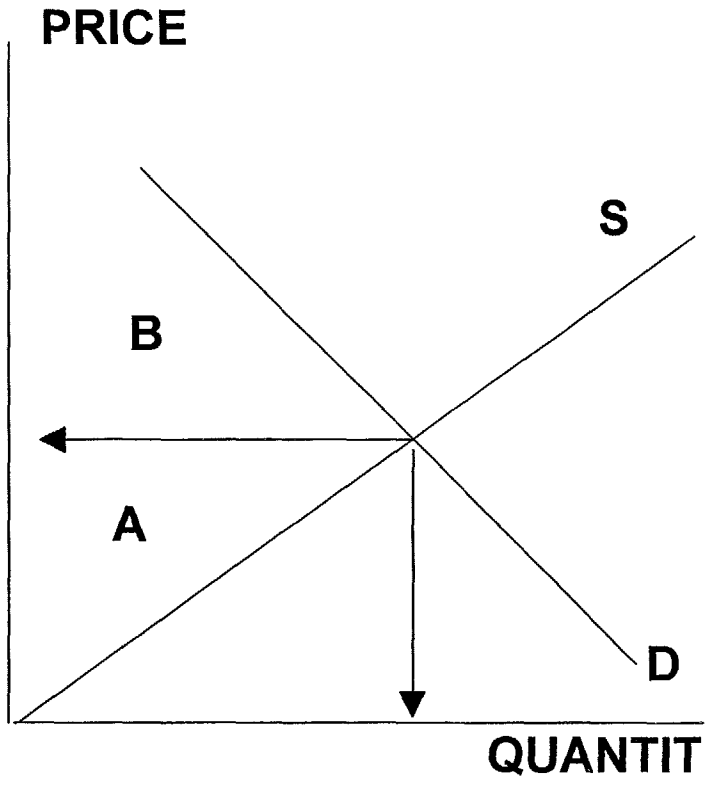
- ECONOMIC FOUNDATION FOR UTILTIY PRICING
- ECONOMIC FUNCTIONS OF PRICING
- COSTING OF ELECTRICITY
- COST ALLOOCATION
- CRITERIA FOR SOUND RATE STRUCTURES
- COST OF SERVICE RATES
- DEMAND-BASED RATES
- MARGINAL COST PRICING
- ALTERNATIVE RATES DESIGNS
- SPECIFIC PRICING ISSUES
- PRICE CAPS

ECONOMIC FOUNDATION FOR UTILITY PRICING

- WELFARE ECONOMICS
  - PRESUMES VOLUNTARY EXCHANGE IN WHICH BOTH BUYERS AND SELLERS ARE MADE BETTER OFF IN THE ACTIVITY OF EXCHANGE
  - THERFORE, EXPECTED BENEFIT-COST RATIO FROM TRADING IS ALWAYS GREATER THAN ONE
  - COMPONENTS
    - PRODUCER SURPLUS
    - CONSUMER SURPLUS
  - WELFARE LOSS OCCURS WHEN PRICES DEVIATE FROM MARGINAL COST

INDIVIDUAL MARKET EXCHANGE

- SUPPLY PRICE = LOWEST PRICE SELLER WOULD ACCEPT
- DEMAND PRICE = MAXIMUM PRICE THAT BUYER WOULD ACCEPT
- NET GAIN FROM TRADE =
  - BUYER, AREA B = CONSUMER SURPLUS
  - SELLER, AREA A = PRODUCER SURPLUS



PROPRIETARY INFORMATION

ECONOMIC FOUNDATION FOR UTILITY PRICING

- ECONOMIC EFFICIENCY OBJECTIVES: GOODS AND SERVICES PASS FROM PLACES OF LOW VALUATION TO PLACES OF HIGH VALUATION
- WITH MARGINAL COST PRICING, MARGINAL BENEFITS (DEMAND) = MARGINAL COST (SUPPLY)

PROPRIETARY INFORMATION

ECONOMIC FOUNDATION FOR UTILITY PRICING

- WHERE P = MC DOES NOT RESULT IN SUFFICIENT REVENUES (I.E , REVENUES THAT COVER A UTILIT'S COST OF CAPITAL), ADJUSTMENTS TO RATES NEED TO BE MADE (FROM AN ECONOMIC-EFFICIENCY PRESPECTIVE, ADJUSTMENTS SHOULD BE MADE ON THE FIRST OR EARLY "BLOCKS" SO THAT MARGINAL BEHAVIOUR IS NOT AFFECTED)
  - MARGINAL COST PRICING CAN CONFLICT WITH CERTAIN GOVERNMENTAL/REGULATORY OBJECTIVES
    - ECONOMICALLY EFFICIENT
    - POSSIBLE LARGE ONE-TIME INCREASE IN TARIFFS
    - REVENUE RECONCILIATION WOULD TEND TO FAVOR LARGE (PRICE-ELASTIC) CUSTOMERS AND HURT SMALL (PRICE-INELASTIC) CUSTOMERS

ECONOMIC FUNCTIONS OF PRICING

- CLEARING MARKETS - PREVENTING SHORTAGES OR UNDER-USE OF RESOURCES
- GUIDING CONSUMER DECISIONMAKING - ADVANCING EFFICIENT CONSUMER CHOICES
- RATIONING OUTPUTS - ALLOCATING SCARCE RESOURCES TO THEIR HIGHEST USER
- GUIDING OPERATIONAL DECISIONS OF UTILITY MANAGEMENT - ADVANCING LEAST COST PROCUREMENT, ETC)
- GUIDING INVESTMENT DECISIONS OF UTILTY MANAGEMENT
- GUIDING ENTRY- EXIT DECISIONS

ECONOMIC GOALS OF REGULATION

- ECONOMIC EFFICIENCY
- EQUITY
  - PRESUMPTION : REGULATION CORRECTS FOR MARKET FAILURES THAT WOULD CAUSE A UTILITY TO ACT LIKE AN UNREGULATED MONOPOLIES; I.E., TO CHARGE EXCESSIVE PRICES, PRODUCE TOO LITTLE OF ITS SERVICES, AND EARN EXORBITANT PROFITS

COST ALLOCATION

- PRINCILPE 1· "HE WHO CAUSE A COST SHOULD PAY FOR THE COST" - COST CAUSATION PRINCIPLE
  - *(PROBLEM SOME COSTS (E G , CAPITAL COSTS) CANNOT BE DIRECTLY ATTRIBUTABLE TO A PARTICULAR CUSTOMER)*
- PRINCIPLE 2. "NO ONE SHOULD PAY MORE THAN A 'FAIR SHARE' "
  - *(PROBLEM HOW DO WE DETERMINE WHETHER CERTAIN CUSTOMERS ARE CROSS-SUBSIDIZING OTHER CUSTOMERS)*
- PRINCIPLE 3· "COST ALLOCATION SHOULD ALLOW A REGULATED FIRM TO COLLECT SUFFICIENT REVENUES"
  - *(PROBLEM CUSTOMERS WITH CHOICES MAY AVOID THE COSTS ALLOCATED TO THEM OR TO THEIR CUSTOMER CLASS)*

COST ALLOCATION

- ALLOCATION ISSUES
  - WHAT FACTORS AFFECT A UTILITY COSTS?
    - ENERGY USE
    - INSTANTENOUS DEMAND
    - NUMBER OF CUSTOMERS

PROPRIETARY INFORMATION

COST ALLOCATION

- WHAT SHARE OF A UTILITY'S COSTS IS ATTRIBUTABLE TO A PARTICULAR CUSTOMER?
- IF INDUSTRIAL CUSTOMERS ACCOUNT FOR 60% OF THE TOTAL KWH CONSUMPTION OF A UTILITY, THEY SHOULD BE RESPONSIBLE FOR 60% OF THE TOTAL FUEL COSTS.
- LOAD FACTORS IS AN IMPORTANT DETERMINANT OF CAPACITY COST ALLOCATION

BASIC PARTS OF A TARIF

- ENERGY CHARGE ($/MWH)
- CUSTOMER CHARGE ($/MONTH)
- DEMAND CHARGE ($/KW)

PROPRIETARY INFORMATION

STANDARD CRITERIA FOR RATES SETTING

- UNDERSTANDABILITY, PIBLIC ACCEPTABILITY AND ADMINISTRATIVE FEASIBILITY
- FREE OF CONTROVERSY
- REVENUE SUFFICIENCY
- REVENUE STABILITY
- STABILITY OF RATES THEMSELVES
- FAIR APPORTIONMENT OF COSTS AMONG CUSTOMERS
- AVOIDANCE OF "UNDUE" DISCRIMINATION
- ENCOURAGEMENT OF EFFICIENCY

OTHER CRITERIA

- GRADUALISM (AVOID RATE CHOCK)
- EMPLOYMENT AND ECONOMIC DEVELOPMENT
- ENVIRONMENTAL PROTECTION
- ENERGY CONSERVATION

FAIR AND REASONABLE PRICES

- PROVIDE AFFORDABLE SERVICE TO ALMOST ALL CONSUMERS
- REFLECT ONLY PRUDENT COSTS OF A UTILITY
- REFLECT UTILITY'S COST OF SERVING DIFFERENT CLASSES OF CUSTOMERS AND OF PROVIDING DIFFERENT SERVICES
- ALLOW THE UTILITY TO RECEIVE SUFFICIENTB REVENUES TO ATTRACT NEW CAPITAL
- PROHIBIT UNDUE DISCRIMINATION AGAINST ANY CUSTOMER CLASS OR SERVICE (E G , RATES SHOULD NOTMFALL BELOW SHORT-RUN MARGINAL COST)
- IN COMPETITIVE MARKETS, ANY PRICE THAT IS TRANSACTED BETWEEN A BUYER AND A SELLER

PRICING FROM DIFFERENT PERSPECTIVES- LIKELY CONFLICTS

➤UTILITY

- REVENUES SHOULD COVER FULL COSTS
- DESIGN SHOULD ACCOMMODATE COMPETITIVE FORCES
- FAIR RETURN ON CAPITAL SHOULD BE EARNED

PRICING FROM DIFFERENT PERSPECTIVES- LIKELY CONFLICTS

➤CONSUMERS

- TARIFFS SHOULD BE AFFPRDABLE
- TARIFFS SHOULD BE EQUITABLE
- TARIFFS SHOULD EXCLUDE IMPRUDENT COSTS
- TARIFFS SHOULD BE UNDERSTANDABLE

PRICING FROM DIFFERENT PERSPECTIVES- LIKELY CONFLICTS

➤ REGULATORS

- TARIFFS SHOULD BE COMPATIBLE WITH PRUDENT COSTS AND OTHER CRITERIA
- TARIFFS SHOULD BE JUST AND REASONABLE

➤ SOCIETY

- TARIFFS SHOULD PROMOTE ECONOMIC EFFICIENCY
- TARIFFS SHOULD PROMOTE ECONOMIC GROWTH

GENERAL APPROACHES TO PRICING

- APPROACHES
  - DEMAND-BASED
  - COST-OF-SERVICE
  - MARGINAL COST

PROPRIETARY INFORMATION

GENERAL APPROACHES TO PRICING

➤ASSESSMENT

	STRENGTHS	WEAKNE2SS
DEMAND-BASED	MARKET SENSITIVE	DISCRIMINATORY
COST-OF-SERVICE	SIMPLE, RECONCIABLE WITH REVENUE REQUIREMENTS	RIGID, NOT MARKET SENSITIVE
MARGINAL COST	ECONOMICALLY EFFICIENT	MEASUREMENT PROBLEM, REV RECONCILATION ADJUSTMENT

GENERAL APPROACHES TO PRICING

- US. REGULATION TYPICALLY REQUIRES COST-BASED PRICING (ALLOWING FOR AN ADEQUATE RATE OF RETURN) OF MONOPOLISTIC SERVICES
- US. REGULATORS HAVE THE AUTHORITY TO DEVIATE FROM COST-BASED PRICING IN ORDER TO ACHIEVE SOCIAL OBJECTIVES (E.G., AFFORDABILITY TO LOW-INCOME HOUSEHOLDS)

COST-OF-SERVICE RATES

- DOWNPLAY OF ABILITY TO PAY AND VALUE OF SERVICE
- NEED TO DEFINE COSTS AND HOW THEY SHOULD BE ALLOCATED TO DIFFERENT CUSTOMERS
- IN PRACTICE, RATES WOULD SOMEWHAT DEVIATE FROM COSTS IN ORDER TO ACHIEVE CERTAIN REGULATORY OBJECTIVES

COST-OF-SERVICE RATES

- COSTS ARE SEGMENTED INTO ASSIGNABLE COSTS AND COMMON OR JOINT COSTS
- PROBLEMS
  - DEMAND CONDITIONS ARE DE-EMPHASIZED
  - NO AGREEMENT ON HOW TO ALLOCATE COMMON AND JOINT COSTS
  - HISTORICAL COSTS MAY BEAR LITTLE RESEMBLANCE TO FORWARD-LOOKING MARGINAL COSTS

MARGINAL COST PRICING

- NEED TO CALCULATE HOW A UTILITY'S TOTAL COSTS WOULD INCREASE WITH AN ADDITIONAL UNIT OF SERVICE
- THE ECONOMIST WOULD DEFINE MARGINAL COST IN TERMS OF WHAT SOCIETY HAS TO GIVE UP IN ORDER TO CONSUME ADDITIONAL UNIT OF A UTILITY SERVICE (E G , kWh OF ELECTRICITY)
- TASK IS NOT TO ALLOCATE COSTS TO CUSTOMER CLASSES, BUT TO CALCULATE UNIT COSTS
- CAN BE APPLIED TO PEAK/OFF-PEAK PRICING AND THE PRICING OF INDIVIDUAL SERVICES

MARGINAL COST PRICING

- IF DONE PROPERLY, MEASURED COSTS ARE "ECONOMIC" NOT "ACCOUNTING"
- EMBEDDED (AVERAGE HISTORICAL) COSTS AND MARGINAL COSTS CAN GREATLY DIFFER

MARGINAL COST PRICING

➤PROBLEMS WITH MARGINAL COST PRICING

- SHORT-RUN OR LONG-RUN? (SHORT-RUN DOES NOT INCLUDE COST OF ADDITIONAL CAPACITY; LONG-RUN IS APPROXIMATED BY LEVELIZED LONG-RUN INCREMENTAL COST PER UNIT)
- IN MOST APPLICATIONS, USES ACCOUNTING COSTS
- LIKELY TO CAUSE UTILITY'S REVENUE TO DEVIATE FROM ITS FULL COSTS
- SECOND-BEST PROBLEM (DISTORTIONS IF OTHER GOODS AND SERVICES ARE NOT PRICED ON THE BASIS OF MARGINAL COST)

ALTERNATIVE RATE DESIGNS

- FLAT RATE
- UNIFORM RATE
- DECLINING-BLOCK RATE
- INCREASING-BLOCK (E.G., LIFE-LINE) RATE
- SEASONAL RATE
- TIME-OF-USE RATE

PROPRIETARY INFORMATION

ALTERNATIVE RATE DESIGNS

- AN ILLUSTRATION: LIFELINE RATES
  - FORM OF INVERTED BLOCK RATE
  - RATIONALE
    - CORRECTS FOR REGRESSIVE EFFECTS OF DECLINING BLOCK RATES
    - ASSURES BASIC SERVICE TO LOW INCOME CONSUMERS
    - FOR UTILITIES WITH INCREASING MARGINAL COSTS, COMPATIBLE WITH PROMOTING ECONOMIC EFFICIENCY

ALTERNATIVE RATE DESIGNS

➤ CRITICISMS

- ABUSE BY AFFLUENT CONSUMERS
- CROSS SUBSIDIZATION (UNDER DECREASING OR CONSTANT MARGINAL COST)
- INEFFECTIVE AND INEFFICIENT METHOD FOR MAKING UTILITY SERVICES AFFORDABLE - UTILITY PRICING SHOULD NOT BE USED TO ASSIST LOW-INCOME HOUSEHOLDS

TYPICAL RATEMAKING PROCESS IN THE US.

➤ STEPS

- DEVELOPMENT OF REVENUE FORECAST FOR UTILITY'S EXISTING RATES
- DETERMINATION OF THE UTILITY'S REVENUE REQUIREMENT (I E , FULL COSTS) INCLUSIVE OF MEETING EARNING TARGETS OR DEBT SERVICE REQUIREMENTS
- COST-OF-SERVICE ANALYSIS (MARGINAL COST, EMBEDDED COST)
- ALLOCATION OF THE OVERALL REVENUE REQUIREMENTS TO CUSTOMER CLASSES
- RATE AND TARIFF DESIGN
- APPROVAL BY INTERNAL MANAGEMENT AND EXTERNAL REGULATORS

REVENUE REQUIREMENTS

☞THE REVENUE REQUIREMENTS EQUATION:

R=REVENUE REQUIREMENTS [TOTAL COST OF SERVICE] = O + D + T + r.B

where O = operating expenses

D = annual depreciation charges

T = taxes

r = permitted rate of return [cost of capital]

B = rate base = asset book value = [V-d]

where V = rate base valuation

d = accumulated or accrued depreciation

REVENUE REQUIREMENTS

r = rate of return [return on bonds and common stock] =
k[E/C] + i [I/C]

where:

k = cost of equity capital

E = equity capital

I = cost of debt capital [weighted average]

I = debt capital

C = total equity/debt capital

thus r = weighted sum of the cost of capital

REVENUE REQUIREMENTS

- THE EXPANDED REVENUE REQUIREMENT EQUATION: $R = O + D + T + [K(E/C) + I(I/C)]B$

✓ X = TOTAL EXPENSES $= O + T + D$

A. $R - X$ = UTILITY OPERATING INCOME

B. X/R = UTILITY OPERATING RATIO

STEPS IN COST ALLOCATION

- FUNCTIONALIZATION (E.G., GENERATION, TRANSMISSION, DISTRIBUTION)
- CLASSIFICATION (E.G., ENERGY, DEMAND, CUSTOMER)
- ALLOCATION TO COSTING PERIODS (PEAK, OFF-PEAK, NON-TIME DIFFERENTIATED)
- ALLOCATION TO CUSTOMER CLASSES (RESIDENTIAL, COMMERCIAL, INDUSTRIAL)

COMPONENTS OF A TYPICAL US. ELECTRIC BILL

- DEMAND CHARGE (COST OF MEETING CUSTOMER'S MAXIMUM DEMAND, INCLUDES THE COST OF CAPITAL AND OTHER FIXED EXPENSES ASSOCIATED WITH GENERATING PLANTS, TRANSMISSION LINES, SUBSTATIONS AND PART OF DISTRIBUTION SYSTEM)
- ENERGY CHARGE (COSTS ASSOCIATED WITH AMOUNT OF kWh CONSUMED, LARGELY FUEL AND LABOR EXPENSES)
- CUSTOMER CHARGE (COST OF BEING ON THE SYSTEM, E.G., ACCESS CHARGE)
- FUEL ADJUSTMENT COSTS (CHANGES IN FUEL COSTS OVER SOME BASE PERIOD)
- TAXES

VALUE OF SERVICE PRICING

- FORM OF PRICE DISCRIMINATION DIFFERENCES IN PRICES NOT EXPLAINED BY UNEQUAL COSTS (I E., THE PRICE TO MARGINAL COST RATIO VARIES ACROSS CUSTOMERS)
- PRINCIPLE OF ALLOCATING COSTS TO DIFFERENT SERVICES BASED ON DEMAND CHARACTERISTICS (I E , WHAT THE MARKET WILL BEAR)
- HIGHER PRICES TO CUSTOMERS WITH LOW PRICE ELASTICITY OF DEMAND
- REGULATED FIRM COVERS, AT MINIMUM, VARIABLE COSTS
- RESULTS IN DISPARATE PROFIT MARGINS ACROSS DIFFERENT CLASSES OF SERVICE

VALUE OF SERVICE PRICING

- CAUSE PRICES TO DIFFER FROM MARGINAL COSTS; THUS WELFARE LOSSES OCCUR
- ATTRACTIVE WAY OF INCREASING A FIRM'S PROFITABILITY
- WITH COMPETITION FOR SOME UTILITY SERVICES, IT WILL GENERATE LOW RATIOS OF PRICE TO COST FOR CUSTOMERS HAVING CHOICES OF SUPPLIERS, RELATIVE TO THOSE CUSTOMERS WHO REMAIN "CAPTIVE" TO THE UTILITY

REASONS FOR A UTILITY TO PRICE DISCRIMINATE

- REDUCE SURPLUS CAPACITY
- IMPROVE UTILIZATION OF EXISTING CAPACITY
- ACCOMMODATE COMPETITIVE FORCES
- BOOST PROFITS THROUGH INCREASED SALES TO PRICE-ELASTIC CUSTOMERS

BRITISH-STYLE REGULATION (PRICE CAPS)

➤FEATURES

- FORMAL RATE REVIEW LIE OUTSIDE THE CONTROL OF THE UTILITY
- REGULATOR DOES NOT CONTROL PROFITS (AT LEAST BETWEEN FORMAL PERFORMANCE REVIEWS) BUT ONLY THE MAXIMUM AVERAGE PRICE FOR A SPECIFIED "BASKET OF SERVICES"
- PRESUMABLY, LESS REGULATORY OVERSIGHT IS REQUIRED OVER TIME WHEN COMPARED WITH US - STYLE COST OF SERVICE
- UTILITY IS GIVEN FLEXIBILITY FOR INDIVIDUAL SERVICES WITHIN A DESIGNATED "BASKET"

BRITISH-STYLE REGULATION (PRICE CAPS)

➤STYLIZED OPERATION

$$P' = (PI - X) \pm Z$$

WHERE

P' = ANNUAL ALLOWABLE PRICE CHANGE (%)

PI = PRICE INDEX (E.G., RETAIL PRICE INDEX, COST INDEX FOR COMPARABLE UTILITIES)

X = PRODUCTIVITY OFFSET (E G., RESIDUAL PARAMETERS THAT ACCOUNTS FOR EXPECTED REVENUES, RISKS, AND RATE OF RETURN)

Z = EXOGENOUS COSTS (COST PASSTHROUGH)

BRITISH-STYLE REGULATION (PRICE CAPS)

➤KEY QUESTIONS

- WHAT PRICE INDEX TO USE?
- HOW SHOULD THE PRODUCTIVITY OFFSET BE DEFINED? WHAT SHARE OF THE BENEFITS FROM EXPECTED PRODUCTIVITY GAINS SHOULD GO TO CONSUMERS?
- WHAT SHOULD BE THE BASE PRICE?
- WHAT SERVICES SHOULD BE COVERED BY A PRICE CAP? WHAT SHOULD BE THE UP-FROM REVIEWS?
- SHOULD A PRICE FLOOR BE ESTABLISHED FOR INDIVIDUAL SERVICES?
- WHAT COST COMPONENTS SHOULD BE COVERED BY A PRICE CAP?

BRITISH-STYLE REGULATION (PRICE CAPS)

➤POTENTIAL BENEFITS

- THE UTILITY HAS STRONG INCENTIVE TO BE COST-EFFICIENT
- CONSUMERS SHARE IN THE BENEFITS OF A MORE EFFICIENT UTILITY
- THE UTILITY CAN COMPETE ON AN EQUAL BASIS WITH OTHER SUPPLIERS IN PRICE-SENSITIVE MARKETS
- THE UTILITY'S PRICES WILL MOVE TOWARD EFFICIENT "SECOND BEST" LEVELS

BRITISH-STYLE REGULATION (PRICE CAPS)

- ASSUMING SEPARATE PRICE CAPS FOR EACH CUSTOMER CLASS, PRICE-INELASTIC CONSUMERS CAN BE PROTECTED FROM COMPETITION IN OTHER MARKETS
- THE REGULATOR ENCOUNTERS LESS REQUEST FORMAL REVIEWS THAN UNDER COST-OF-SERVICE REGULATION
- UTILITY CONSUMERS WOULD BE PROTECTED FROM A UTILITY'S DIVERSIFIED ACTIVITIES - THE INABILITY OF THE UTILITY TO PASS THROUGH HIGHER REPORTED COSTS TO RETAIL CUSTOMERS REDUCES THE LIKELIHOOD OF SELF-DEALING ABUSE, CROSS-SUBSIDIZATION, AND COLLUSIVE AGREEMENTS

BRITISH-STYLE REGULATION (PRICE CAPS)

➤POTENTIAL PROBLEMS

- THE UTILITY COULD HAVE INCENTIVE TO PROVIDE LOWER QUALITY/RELIABILITY OF SERVICE
- THE UTILITY COULD ENGAGE IN CROSS-SUBSIDIZING COMPETITIVE SERVICES
- THE UTILITY MAY ENCOUNTER CONDITIONS BETWEEN REVIEWS THAT RESULT IN UNANTICIPATED HIGHER OR LOWER PROFITS
- PRICES MAY BE CONSIDERED UNFAIR (RAMSEY PRICES)
- CONSUMERS MAY BENEFIT LITTLE FROM A UTILITY'S ACTUAL PRODUCTIVITY GAINS (I.E , THE X PARAMETERS IS SET EXCESSIVELY LOW)

EDS

Day 2

8 30 - 9 45 (Dr David Boyd Continue)

- Sample cost allocation methods
- Problems presented by cross-subsidy

9 45 - 10 00 Coffee Break

10 00 - 12 00

- Demand-side management and conservation

12 00 - 1 00 Lunch

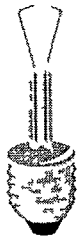
1 00 - 2 45 **Alternatives to Utility Service Disconnection** (Dr Youssef Hegazy)

- Concerns of affordability and availability
- Achieving an appropriate fairness Vs efficiency tradeoff
- Disconnection moratoria and restriction policies

2 45 - 3 00 Coffee Break

3 00 - 5 00

- Billing and pricing arrangements
- Non-price preventive customer service programs
- Smart Cards
- Evaluation of USA utilities experience with alternative programs



ALTERNATIVES TO EFFICIENT SERVICE DISCONNECTION

USAID/IIE WORKSHOP

Economic Management Of a Distribution Companies

MANILA, PHILIPPINES,

August 25 - September 5, , 1997

EDS Utilities

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CONCERNS ABOUT AFFORDABILITY AND AVAILABILITY

- ALTHOUGH ECONOMIC EFFICIENCY MAY REQUIRE HIGHER PRICES THAN ARE NOW CHARGED TO SMALLER CUSTOMERS, CHARGING THESE CUSTOMERS HIGHER RATES MIGHT MAKE THE SERVICE UNAFFORDABLE.
- IF ELECTRIC SERVICE BECOMES UNAFFORDABLE, IT EFFECTIVELY IS UNAVAILABLE
- HOWEVER, IF RATES DO NOT PRODUCE ADEQUATE REVENUES TO ATTRACT CAPITAL, SERVICE MIGHT BE UNAVAILABLE, WHETHER OR NOT IT WOULD HAVE BEEN AFFORDABLE

EDS Utilities

CONCERNS ABOUT AFFORDABILITY AND AVAILABILITY

- TRADITIONALLY, COST ALLOCATION UNDER FULLY ALLOCATED COST OF SERVICE FAVORED RESIDENTIAL CUSTOMERS AND DISFAVORED LARGE INDUSTRIAL CUSTOMERS
- SMALLER CUSTOMERS, PARTICULARLY RESIDENTIAL CUSTOMERS, WERE FAVORED IN ORDER TO MAKE ELECTRICITY MORE AFFORDABLE. THEY PAID THEIR OUT-OF-POCKET COSTS AND A SMALLER SHARE OF THE CAPITAL COST
- LARGER CUSTOMERS, PARTICULARLY LARGE INDUSTRIAL AND COMMERCIAL CUSTOMERS, WERE DISFAVORED IN ORDER TO RAISE SUFFICIENT REVENUES IN ORDER TO RAISE CAPITAL TO MAKE ELECTRICITY WIDELY AVAILABLE. THEY PAID THEIR OUT-OF-POCKET COSTS PLUS A LARGER SHARE OF THE CAPITAL COST

EDS Utilities

CONCERNS ABOUT AFFORDABILITY AND AVAILABILITY

- THIS SYSTEM WORKED WELL UNTIL COMPETITION WAS INTRODUCED INTO THE ELECTRIC AND NATURAL GAS SECTORS.
- AS LARGER CUSTOMERS GET CHOICES, THEY BECOME ELASTIC.
- PRICES NEED TO READJUST THEMSELVES TO RAMSEY PRICING TO ACHIEVE SUFFICIENT REVENUES
- PRICES FOR SMALLER CUSTOMERS WITHOUT CHOICES RISE, WHILE PRICES FOR LARGER CUSTOMERS WITH CHOICES FALL

EDS Utilities

CONCERNS ABOUT AFFORDABILITY AND AVAILABILITY

- HOW CAN A COMMISSION BALANCE EFFICIENCY CONCERNS WITH THE EQUITY CONCERNS OF AFFORDABILITY AND AVAILABILITY
- PRICE CAPS FOR CUSTOMERS WITHOUT CHOICES
- ALTERNATIVE PROGRAMS TO MINIMIZE UTILITY SERVICE DISCONNECTION OF RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS
  - PRIOR NOTICE OF DISCONNECTION, INCLUDING THIRD-PARTY NOTICE
  - DATE-BASED OR TEMPERATURE-BASED DISCONNECTION MORATORIA
  - SERVICE LIMITERS

EDS Utilities

CONCERNS ABOUT AFFORDABILITY AND AVAILABILITY

- LIFE-LINE RATES (LOWER RATES FOR THE FIRST BLOCK OF CONSUMPTION)
- INCOME-BASED BILLING (e.g.., 10 %) OF INCOME
- BUDGET BILLING
- PARTIAL PAYMENT AND ARREARAGE FORGIVENESS
- CONSERVATION LOANS
- WEATHERIZATON AND TARGETED CONSERVATION
- ENERGY AUDITS
- BUDGET COUNSELING
- SOCIAL SERVICE REFERRALS FOR FINANCIAL ASSISTANCE

EDS Utilities

EDS

Day 3

8 30 - 9 45 **Business Process** (Dr David Boyd)

- Business Environment
- Business Structures
  - Organizational Model
  - Business Process Model

12 00- 1 00 Lunch

1 00 - 2 45 **Planning Process** (Dr David Boyd)

- Corporate
  - Environment and company capabilities
  - Strategic plan
  - Overall operating and financial plan
  - Planning and budgeting instructions

2 45 - 3 00 Coffee Break

3 00 - 5 00

  - Consolidation of area budgets
  - Regulatory impacts
- Individual
  - Functional action plan
  - Responsibility area budgets

EDS

Day 4

8 30 - 9 45 **Planning Models** (Dr David Boyd)

- Distribution System expansion plan
- Load Forecast
- End Use
- DSM

9 45 - 10 00 Break

1 00 - 12 00

- Rate and Revenue
- Budgeting
- Financial
  - Pro forma financial statements
  - Financing plan
  - Ratios and other factors
  - Economic forecast

12 00 - 1 00 Lunch

1 00 - 2 45 **Activity-Based Management Overview** (Dr David Boyd)

- Relevant and targeted information
- Cross functional Vs discrete departmental work
- Financial management system
- work/project management systems

2 45 - 3 00 Break

3 00 - 5 00 **Performance Measurement** (Dr David Boyd)

- Unit Cost Reporting
- Productivity Reporting

EDS

Day 5	**Planning Model Workshop** (Dr Youssef Hegazy) **(Cost of Service Case Study)**
8 30 - 9 45	Strategic Planning Model Introduction to PORSCREEN II Financial Planning and Reporting Model (FIR) Class Revenue Model (CRM)
94 5 - 10 00	Break
10 00 - 12 00	Cost Of Service Analysis
12 00 - 1 00	Lunch
1 00-2 45	Cost Of Service Analysis Case Study
2 45 - 3 00	Break
3 00 - 5 00	General Discussion

Cost of Service Study

USAID/IIE WORKSHOP

Economic Management Of a Distribution Companies

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Performing Cost of Service Study

- OBJECTIVE
  - –Develop an understanding of how to use the class revenue module to:
    - Perform a cost of service study
    - Model and analyze a utility's rate structure.

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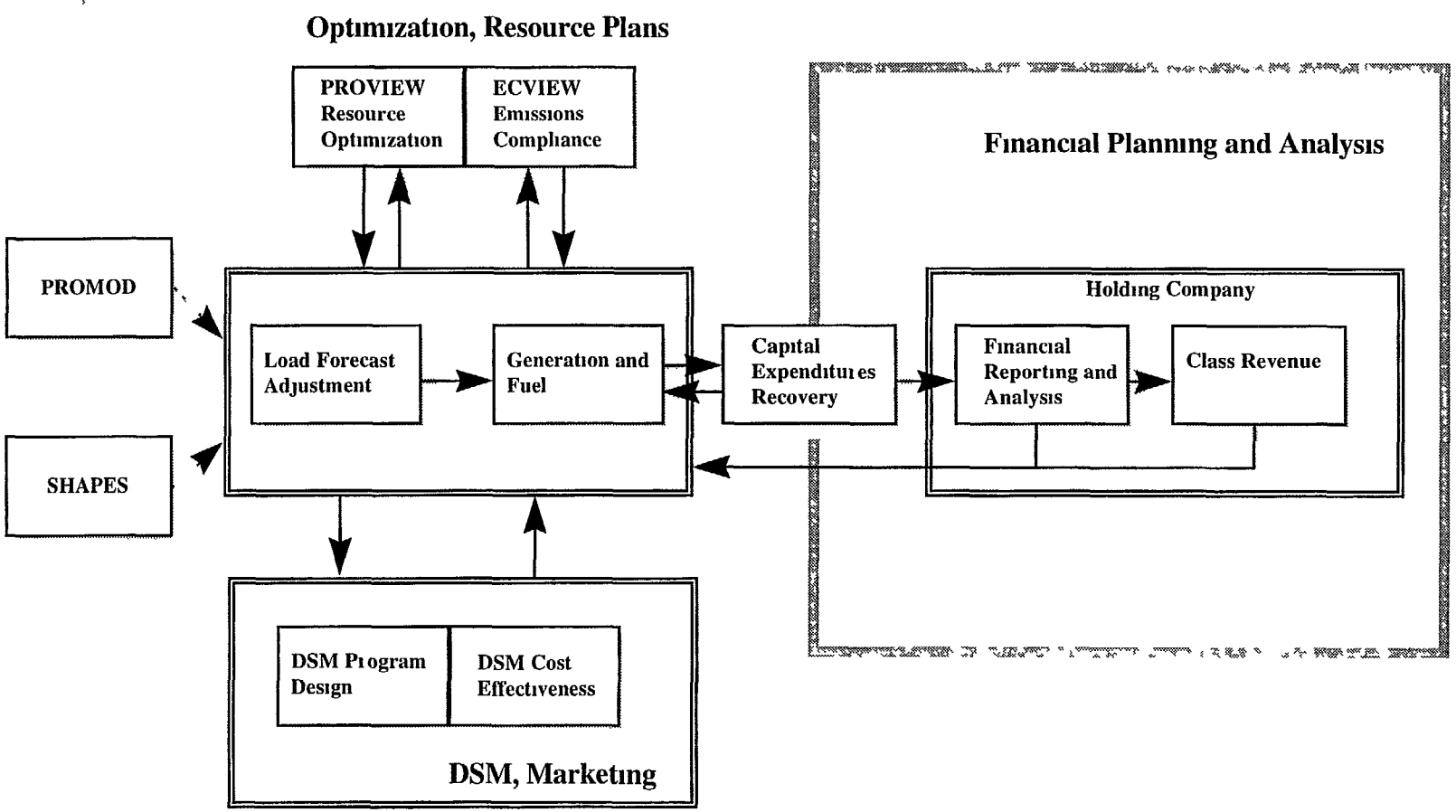
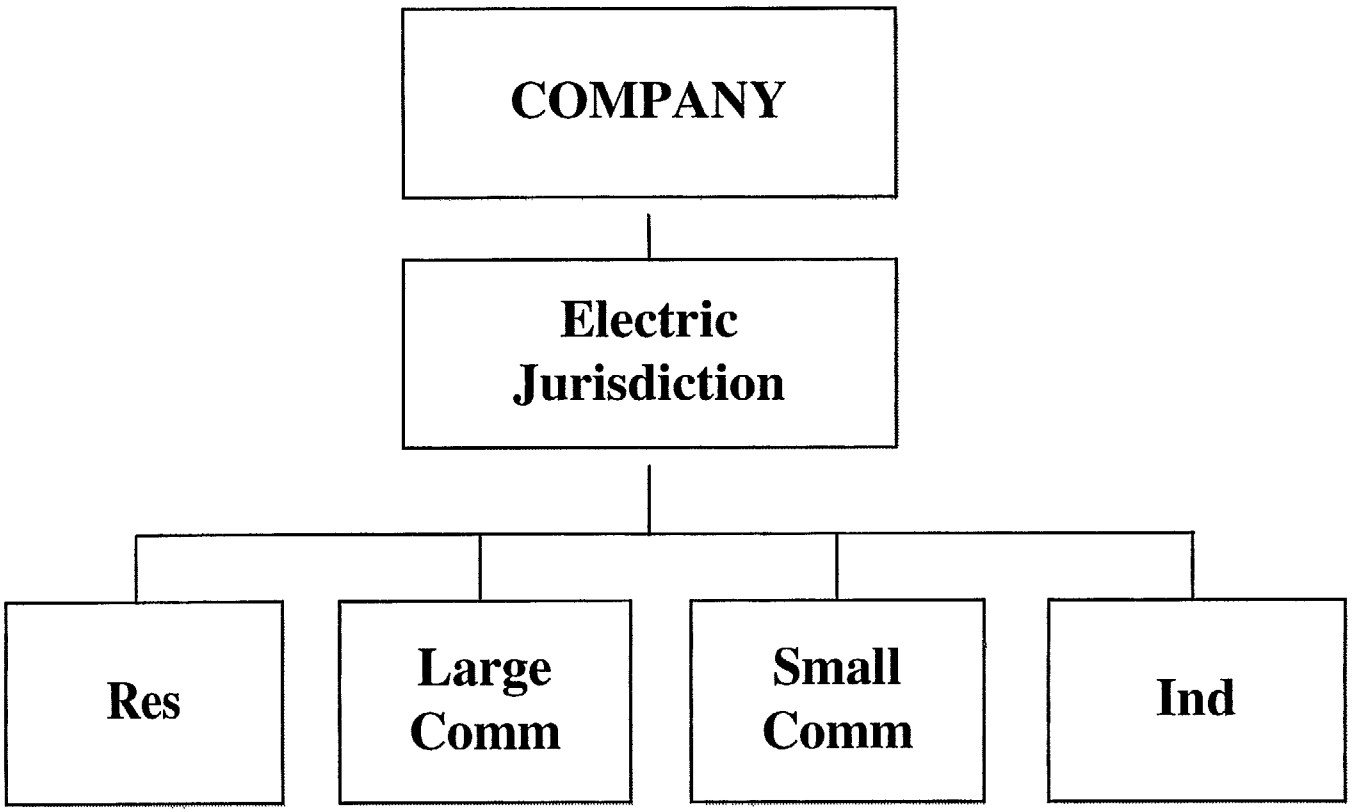
Outline

- **Financial Module Overview**
- Cost of service study
  - Functionalization
  - Classification
  - Allocation
- Revenue calculations
- Rate design methods

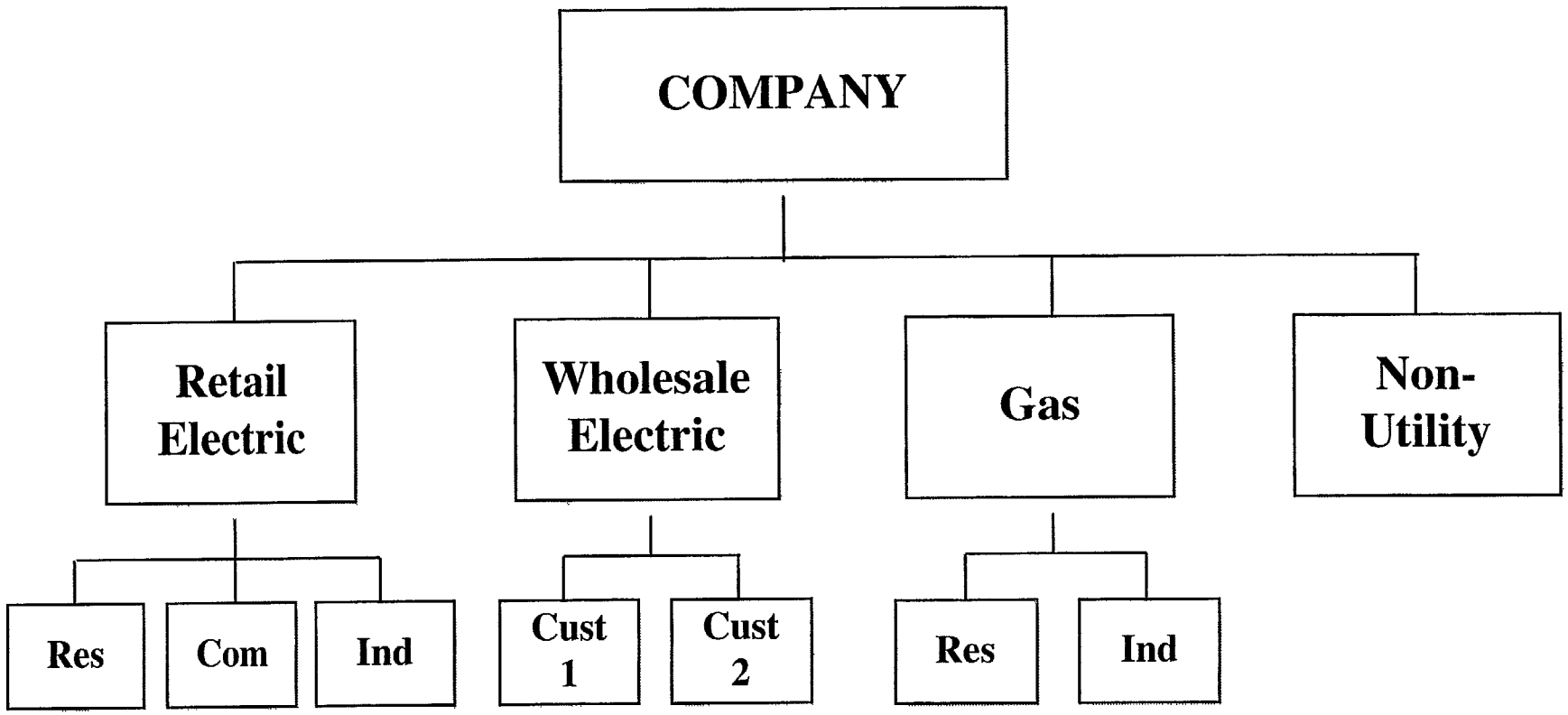
Integrated Planning System: PROSCREEN II



Data Structure: Single Jurisdiction Example



Data Structure: Multiple Jurisdiction Example



Module Capabilities

- The CRM:
  - Allows modeling of multiple rate classes within each jurisdiction
  - Performs allocations
  - Determines revenue requirements at the rate class level
  - Calculates rates at the rate class level

PROSCREEN II

CRM Applications

- Analyzes impacts of DSM programs
- Performs cost of service studies
- Provides price elasticity feedback to LFA
- Calculates impacts of customer additions/losses
- Calculates rate class cross subsidizations
- Evaluates rate design options

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PROSCREEN II

- Sample rate class report

07/20/96 11 17 01 V16 0 R01 0 ELECTRONIC DATA SYSTEMS
PROSCREEN II PAGE 1

FINANCIAL REPORTING AND ANALYSIS MODULE
RATE CLASS REPORT

YEAR 1996
JURISDICTION RETAIL

	RESIDTL	COMMCL	INDUS
TOTAL NET PLANT	801990	521910	343447
TOTAL WORKING CAPITAL	66263	47705	38010
ACCUM DEFERRED TAXES APB 11	156502	101846	67021
	========	========	========
TOTAL END OF YEAR RATE BASE	711751	467768	314436
BASE RATE REVENUES	347280	223674	144240
ALLOWED RATE INCREASE	9922	2259	7212
ADJUSTMENT REVENUES	68034	64646	66567
OTHER REVENUES	5018	1115	112
	========	========	========
TOTAL REVENUES	430254	291695	218131
OPERATING EXPENSES	291729	198933	157014
NORMALIZED TAXES	69228	46358	30543
	========	========	========
TOTAL EXPENSES	360957	245291	187557
RETURN	69297	46404	30574
RETURN ON END OF YEAR RATE BASE	9 74	9 92	9 72
REVENUE REQUIREMENTS			
ENERGY REVENUE	357202	225934	151452
CUSTOMER REVENUE	0	0	0
DEMAND REVENUE	0	0	0
RECOVERED REVENUE TOTAL	357202	225934	151452

Cost Of Service Study Outline

- **Cost of service study**
  - Functionalization
  - Classification
  - Allocation
- Revenue calculations
- Rate design methods

Cost of Service Study:

- Properly associates full cost of utility service to utility customer classes
- Involves:
  - Separation of costs into functional components
  - Categorization of functional costs into classification categories
  - Allocation of costs to jurisdictions
  - Allocation of costs to rate classes

Cost of Service Study

- An overview of the cost accounting process
- Classification and allocation data defaults
- Customizing the data
  - Customized classification
  - Customized allocation

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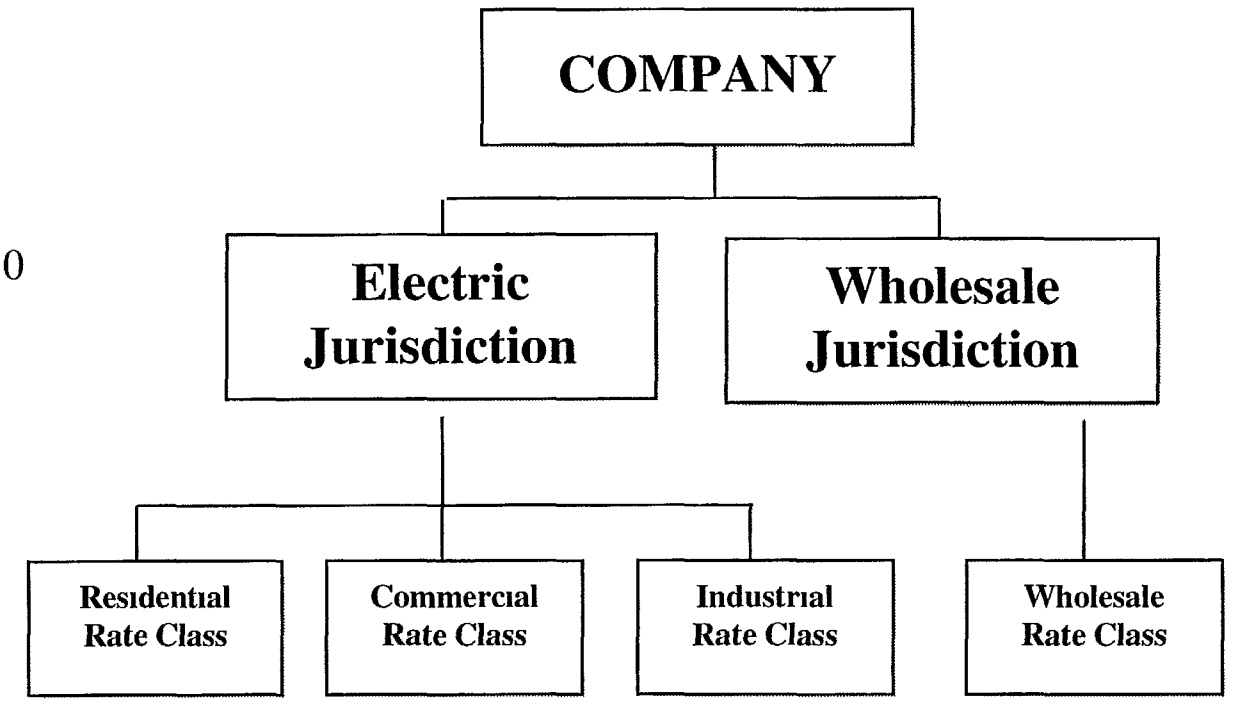
Cost of Service Study

Expense Item
Depreciation

Company Amount $100
Million



Amount Allocated _____ _____ _____ _____

Cost of Service Study

- Separation into **functional** components
- Categorization of functional components into **classification** categories
- **Allocation** to jurisdictions and rate classes

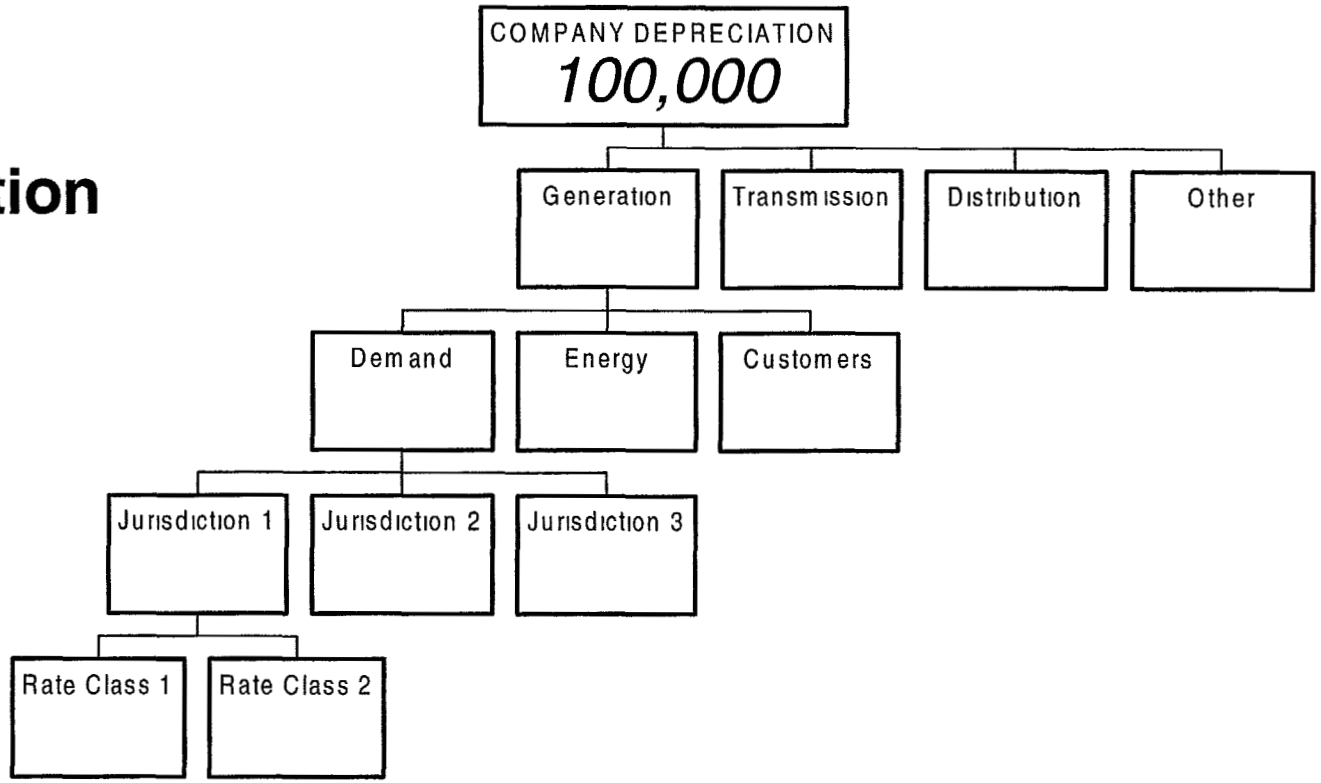
Cost of Service Study

Functionalization

Classification

Allocation

Allocation



Cost of Service Study
Functionalization

- Functionalization involves assigning plant and expenses to categories that describe their function, i.e.:
  - Generation
  - Transmission
  - Distribution
  - General
- Functionalization provides an additional level of detail
  - Asset classes
  - Component schedules

Cost of Service Study
Classification

- Classification involves assigning every plant and expense item to classification categories
- The major classification categories are:
  - Energy
  - Demand
  - Customer
  - Gas

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Cost of Service Study
Classification Example

- Items Primarily Dependent On Demand:

- Items Primarily Dependent On Energy:

- Items Primarily Dependent On Number Of Customers:

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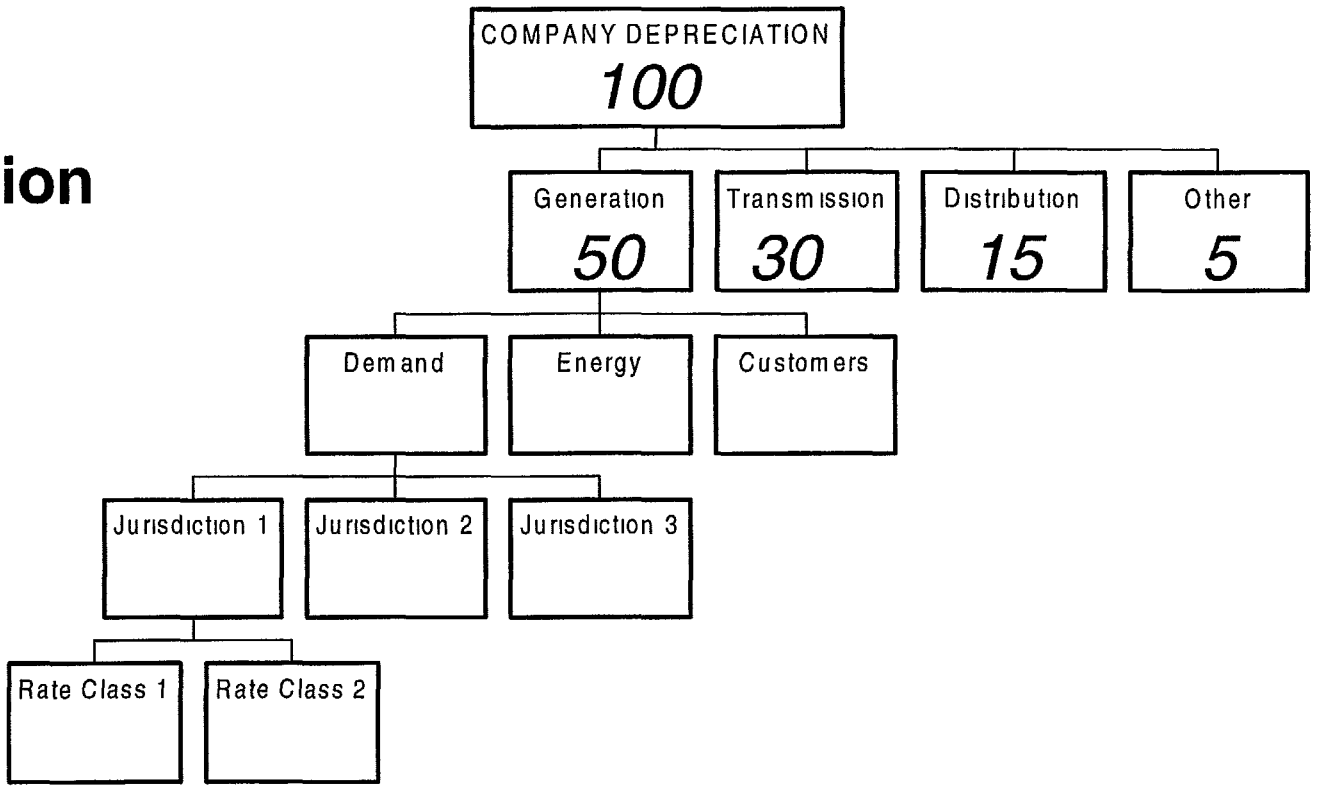
Cost of Service Study Data Development

Functionalization

Classification

Allocation

Allocation



Cost of Service Study

CLASSIFICATION

- Using defaults
- Using customized entries

Cost of Service Study
Default Classification

- Automatically occurs when you do not input classification category names and category types.
- CRM assigns plant and expenses to the following default classification categories:

Category Index	Classification Category Name	Classification Category Type
1	Energy	E
2	Demand	D
3	Customer	C
4	Gas	G

Cost of Service Study : Default Classification

- All items default to demand, with the following exceptions:

Item	Classification Type
Fuel Cost	E
Fuel Inventory	E
Other Production Cost	E
Purchased Power Expense	E
Sales Revenue	E
Variable O&M	E
Administrative And General Expense	C
Customer Accounting	C
Customer Service Expense	C
Gas O&M Expense	G
Gas Inventory	G
Gas Purchase Expense	G

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Cost of Service Study On-Line Exercise

- Using the PROSCREEN II GUI, turn on Diagnostic 7 (Classified Items). Run the FIR for several years and examine the output.

Customized Classification

- Each plant and expense item can be assigned to any classification category
- If multiple classification categories are used, indicate the percentage in each

Cost of Service Study Allocation

- Allocation involves assigning classified plant and expense items to jurisdictions and rate classes.
  - For example, an expense classified by demand would be divided among jurisdictions based on the annualized demand in each jurisdiction.

Cost of Service Study

ALLOCATION

- Using defaults
- Using customized entries

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Jurisdiction and Rate Class Allocation

- Internally calculated allocator profiles

Allocation Method	Definition
1	100 % to Jurisdiction 1 / Rate Class 1
2	Coincident Peak Demand
3	Non-Coincident Peak Demand
4	Average and Excess Demand
5	Electric Energy Requirements
6	Customers
7	Gas MCF Requirements
8	Generic Jurisdiction Energy Requirements
9	Net Plant

Cost of Service Study On-Line Exercise

- Turn on Diagnostic 16 (Rate Class Allocator Data) and Diagnostic 17 (Rate Class Allocators). Run the FIR for several years and examine the output.

Cost of Service Study
Default Allocation

- Eight allocation inputs set defaults for all items

FIR INPUT JURISDICTION ALLOCATION

	Allocator #
DEFAULT DEMAND ALLOCATOR	=2 (CP)
DEFAULT ENERGY ALLOCATOR	= 5 (energy)
DEFAULT CUSTOMER ALLOCATOR	= 6 (# customers)
DEFAULT ASSET CLASS DEMAND ALLOCATOR	= 2 (CP)

FIR INPUT RATE CLASS ALLOCATION

	Allocator #
DEFAULT DEMAND ALLOCATOR	= 2 (CP)
DEFAULT ENERGY ALLOCATOR	= 5 (energy)
DEFAULT CUSTOMER ALLOCATOR	= 6 (# customers)
DEFAULT ASSET CLASS DEMAND ALLOCATOR	= 2 (CP)

- Items classified as gas default to allocator 7

Customized Allocation

- User can create allocator profiles that assign percentages to each jurisdiction or rate class
- Allocator profiles that vary from one year to the next may also be created

Cost of Service Study On-Line Exercise

- Create a simple user specified allocator
- Turn on Diagnostic 16 (Rate Class Allocator Data) and Diagnostic 17 (Rate Class Allocators). Run the FIR for several years and examine the output.

Cost of Service Study On-Line Exercise

- Turn on Diagnostic 12 (Allocated Plant Items by Rate Class) and Diagnostic 13 (Allocated Expense Items by Rate Class). Run the FIR for several years and examine the output.

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Cost of Service Study On-Line Exercise

- Turn on Diagnostic 8 (Allocated And Classified Plant Items). Run the FIR for several years and examine the output.

Cost of Service Study Exercise 2

- Task:
  - In this exercise you will input a customized allocator profile, point an expense or rate base item to that allocator, run the FIR, print reports, and analyze the results.
  - Objective:
  - Become familiar with the required inputs for customized allocation of rate base and expense items.

Revenue Calculation

- Cost of Service Study
  - Functionalization
  - Classification
  - Allocation
- **Revenue Calculations**
- Rate Design Methods

Revenue Calculation Method

- Option 1
  - User-specified rates
- Option 2
  - Input return on rate base
- Option 3
  - Jurisdictional increase plus rate increase cap adder
- Option 0
  - "Floater" rate class
  - Return allocated on ratios of desired return
  - At least one rate class must use this option

PROSCREEN II

Exercise 3

- Task:
  - In this exercise you will change the revenue calculation method for several rate classes, run the FIR module, print reports, and analyze results.
  - Objective:
  - Become familiar with the required inputs for the rate class revenue calculation methods and the results

Cost of Service Study
Outline

- Cost of Service Study
  - Functionalization
  - Classification
  - Allocation
- Revenue Calculations
- **Rate Design Methods**

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Rate Design

- Rate design deals with revenue collection

Customer Costs	1	Customer Revenue
Demand Costs	1	Demand Revenue
Energy Costs	1	Energy Revenue

Rate Design - Rate Design Method

- Option 0
  - User-specified customer and demand charges
  - Energy charge calculated to achieve rate target
- Option 1
  - User-specified percent of customer and demand costs recovered in rate
  - Customer and demand percentages applied to taxes and return cost components
  - Energy charge calculated to achieve rate target
- Option 2
  - Same as option 1 except tax and return cost components are recovered through the energy charge only

Rate Design
On-Line Exercise

- Turn on Diagnostic 18 (Total Cost by Classification Category) and Diagnostic 19 (Unit Cost by Classification Category). Run the FIR for several years and examine the output.

Rate Design
Exercise 4

- Task:
  - In this exercise you will change the rate design method for several rate classes, run the FIR module, print reports, and analyze results.
  - Objective:
  - Become familiar with the required inputs for the rate class rate design methods and the results.

Economic Principles of Pricing and Rate Design

ECONOMIC PRINCIPLES OF RATE DESIGN

INTRODUCTION

Traditionally rate design has been defined as the process of developing prices for utility services from the underlying cost requirements and structure of the utility The primary objective of the ratemaking process has been to establish prices that reflect the utility's cost of service Competition adds a new dimension to the pricing process and requires that utilities consider other factors in developing pricing policies The demands of a competitive market are independent of the regulatory process, and now pricing must reflect regulatory standards as well as the demand of the marketplace

Every utility has an explicit or implicit pricing strategy For many utilities the process is very straightforward Rates follow costs For a growing number the pricing question is more complex as customers demand more specialized treatment

Traditionally, rate design and resource planning were independent processes, utilities designed rates to recover the costs of existing capacity and purchases in a fair and nondiscriminatory manner and developed resource planning to meet load growth Utilities no longer view ratemaking and resource planning as separate process The structure of rates influences both load growth and the cost of effectiveness of conservation and renewable resources to customers For example the structure of rates (the inverting of energy charges, cost-based discounts for conservation, and so on) determines the cost effectiveness to customers of increased insulation and investment in thermal energy storage This affects the need for energy or capacity since utilities can meet forecast winter load increases by purchasing power or by encouraging thermal energy storage and conservation through rate incentives

The typical utility rate making process consists of six major steps (see Figure 1)

1 Development of a revenue forecast for the utility's existing rates

2 Determination of the revenue requirements to meet earnings targets or debt service requirements

3 Cost - of - service analysis

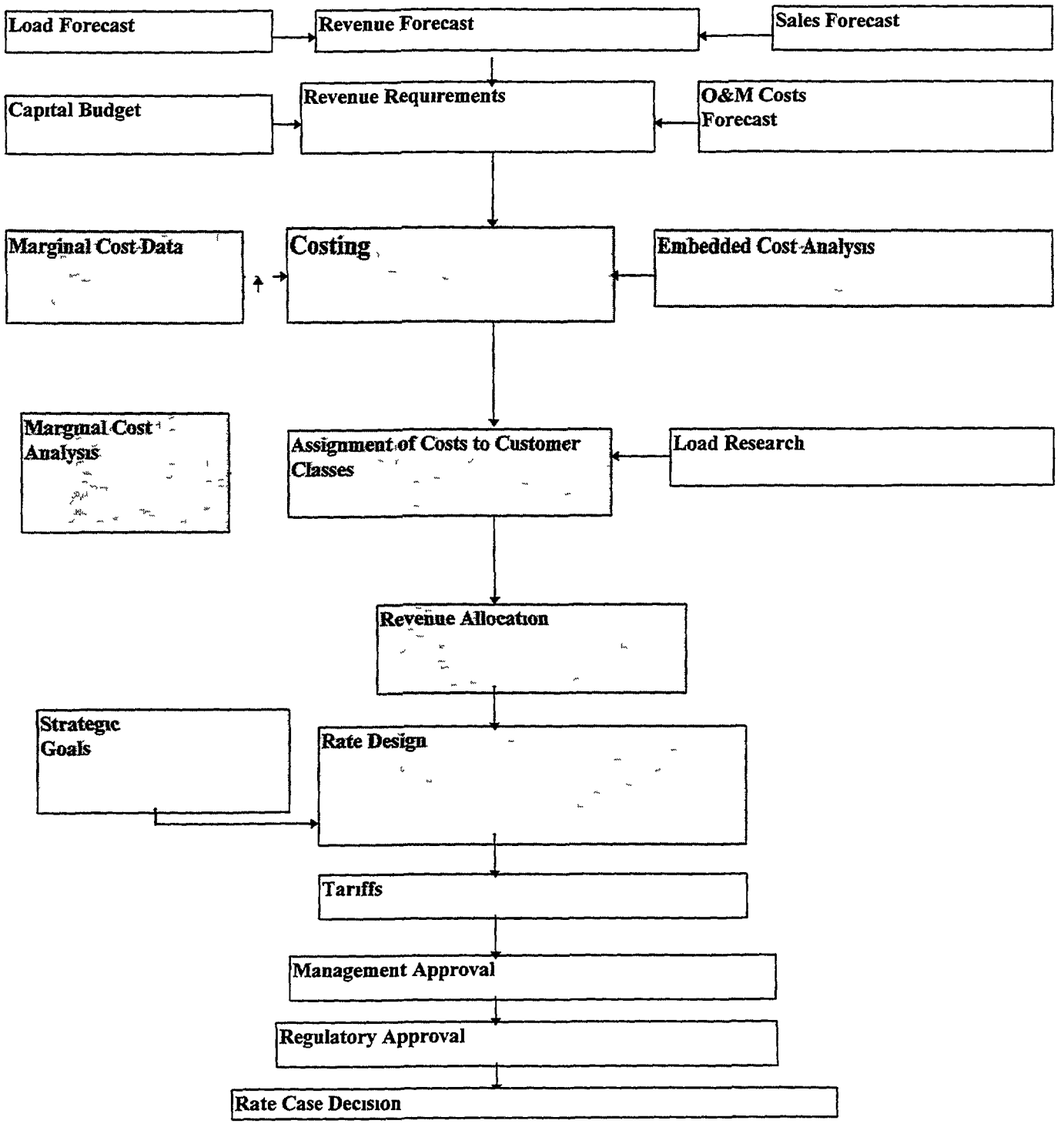
4 Allocation of overall revenue requirements increase to customer classes

5 Design of rates and tariffs

6 Approval by internal management and external regulators

This paper provides an overview of costing, how to calculate marginal costs and accounting costs , rate design and strategic pricing, and revenue and costs allocation

Figure 1 Typical Ratemaking Process



I COSTING

Cost-of -service analysis is the foundation of all traditional rate design approaches Most of the effort for estimating utilities' costs focused on methods of tracking the time variation in a utility's costs

Two costing approaches are reviewed in this paper The first measures marginal cost, or the cost of producing an additional unit of electricity The second is a method for attributing the embedded costs to the hours of the year

1 Marginal Cost Theory and Practice

The cost determinations used in electric utility regulation fall into two broad categories of embedded (or accounting) costs and marginal costs Marginal (or incremental) costs are the additional costs incurred by the utility to provide an additional unit of output. Thus, when a utility uses "forward looking" marginal costs, the utility's historic investment costs are not considered However, historic investments (e g , the utility's capital stocks) influence the current costs of providing an additional unit of output

Utilities measure short-run and long-run marginal costs Short-run marginal costs (SRMC) are the additional costs of providing increments of output over a time period when the utility's capital stock (or electric plant) is fixed Short-run marginal costs include such non-capital costs as fuel, materials, and supplies, variable operation and maintenance expenses, and so on and may include a congestion cost component Long-run marginal costs (LRMC) are the additional costs of providing increments of output when the utility's capital stocks varies Long -run marginal costs include both capital costs and short-run marginal costs Short-run marginal costs fluctuate more than long-run marginal costs, reflecting a changing relationship between installed capacity and load

Historically, marginal costs have not been used in rate design Recently, interest has grown in using marginal costs for this purpose for two reasons

- A theoretical arguments states that the efficiency of the economy may be improved if electricity is priced at marginal costs
- A practical argument states that the efficiency of the electric system may be improved minimizing future cost increases if electricity is priced at marginal cost

The theoretical argument results from the proposition that the pricing of all goods and services at SRMC leads to the most efficient allocation of society s goods and services At any given time the economy has a fixed bundle of productive resources or a finite total potential productive capacity The demand for all goods and services is responsive to price As the price of a commodity lowers, demand for the commodity increases Consumers will continue to demand a commodity until the value or satisfaction they receive from consuming one more unit equals the amount they have to give up to obtain one more unit of the commodity

or the price of the good A basic assumption of economic theory is that the value or satisfaction a consumer receives from consuming an additional unit of a commodity decreases as he/she consumes more of the commodity When the price equals the marginal cost, the value received from consuming one more unit of the good is equal to the cost of producing one more unit of the commodity Resources or consumption cannot be reallocated or rearranged to yield consumers more value or total satisfaction This allocation is efficient or "optimal "

Thus, the major benefit from reflecting marginal costs in the rate design is to provide more efficient cost signals to customers This benefit must be weighted against the problems of measuring and applying these costs These problems include

- Difficulty in measuring the costs (particularly marginal capacity costs)
- The need to reconcile marginal cost-based revenues to established class revenue levels
- second-best considerations

2 Embedded (Accounting) Costs and Time - Differentiated

Embedded costs are the average current costs to the utility based on its historic investment costs Utilities calculate embedded costs to determine the level of rates (and the revenue) that they need to collect and to determine the proportions of the overall revenue requirement to be recovered from the customer classes Utility accounting or embedded cost often varies over the hours of the year A utility can base time-of-use or seasonal rates on either marginal or accounting costs There are four known methods for allocating "generation-related" demand costs to periods These methods are

- Base-Intermediate-Peak (BIP) assigns units to costing periods by a relatively simple technique
- Full Availability Dispatch (FAD) uses unit derating and stacks units under the load curve
- Reconstructing employs traditional production costing methods to determine loading
- Probability of Contribution to Peak (PCP) examines demand-side conditions basing cost allocations on the likelihood that capacity will be required in alternative periods

II Strategic Pricing

This section discusses the importance of utilities developing explicit pricing strategies The purpose is to identify a process whereby utilities can develop, design, and evaluate rate structure options that are responsive to changing market conditions

Rate design Objectives

In utility rate design, utility concerns include

1 Maintaining the costs of electricity to consumers at the lowest feasible level

2 Covering utility operating costs and retaining a sufficient margin to ensure the financial viability of the enterprise

3 Minimizing future costs to consumers

4 Minimizing social and environmental impacts and effects on consumers' income and lifestyles

Electricity consumption, alternative level of rates, and the rate design affect these concerns For ample, utilities may want to establish a rate design that minimizes unpredictable fluctuations in revenues hich might result from an unseasonably mild winter) The rate design can help achieve this objective by overing a proportion of revenues through fixed charges that do not vary with consumption However, any of these areas of concerns can conflict with one or more of the others For example, the desire to intain the financial integrity of the utility In some cases a conflict exists between minimizing current and re costs Social and environmental concerns can also conflict with other objectives

The most appropriate balance between conflicting objectives depends upon the particular economic, icial demographic, and social circumstances facing the utility The particular conditions influence how n weight should be placed on desirable objectives The objectives most often suggested for rates were ilated as

- The related, practical attributes of simplicity, understandability, public acceptability, and feasibility of application
- Freedom from controversies as to proper interpretation
- Effectiveness in yielding total revenue requirements under the fair-return standard
- Revenue stability from year to year
- stability of the rates themselves with a minimum of unexpected changes
- Fairness of the specific rates in the apportionment of total costs of service among the different customers
- Avoidance of undue discrimination in rate relationships

- efficiency of the rate classes and rate blocks in discouraging wasteful use of service while moting all justified types and amounts of use

The ge rate objectives, combined with the utility specific objectives form the basis for the rate structure I rates achieve the stated objectives, the rates are reasonable Utilities may design rates based upon such factors as the cost of service, the purpose for which the product is received, the quantity or the amount received, the different character of the service received, the time of its use, or any other factor that present a substantial difference as a ground of distinction Many factors are properly considered in determining the reasonableness o a utility's rate structure and customer classifications No one factor controls rate design

2 Overview of Strategic Pricing

Every utility has an explicit or implicit pricing strategy Rates follow from a broad set of policy objectives tha match circumstances facing the utility For most utilities, the rate structure has evolved over time as the utility onded to changing market and regulatory conditions As a result, utility rate structures represent a complex mix of rate design considerations including cost of service, value of service and equity considerations Traditional approaches to rate design generally follow five steps

- Determine the relevant billing units
- Evaluate revenues at current rates
- Determine total revenue deficiency at current rates
- Perform cost-of-service study
- Adjust rate elements if necessary to eliminate revenue deficiency

Rate design focuses on adjusting rate elements to recover costs Issues include the anticipated bill impacts on customers in each class and the stability of rates

Strategic pricing is distinguished from traditional rate design approaches by its focus on market conditions Traditional approaches focus on cost recovery However pricing strategies derived from each approach may have different results For example, a market based rate design may rely on the design of competitively prices energy-service options to increase sales and reduce or eliminate an expected revenue deficiency In contrast, a cost-recovery-based rate design may rely on an increase in rates to recover an anticipated revenue deficiency Strategic approaches to rate design generally follow these five steps

- Determine the utility system objectives

- Assess the market conditions that influence the demand for electricity or energy services
- Identify the rate structure alternatives that are responsive to consumer preferences
- Establish the costs of providing options
- Evaluate each option with respect to utility objectives and utility costs

The focus of the rate design is on the market conditions, and the starting point is the customer How much is the consumer willing to pay, bearing in mind that the choices available to the consumer and prevailing prices? The relevant issues for a market-based strategy include competitiveness, price elasticity of demand, customer preferences, and value of service Ideally, strategic pricing is an explicit planning approach to the utility's pricing function It assumes that price influences customer behavior The objective of strategic pricing is to identify and direct the utility's efforts toward specific services and activities that are of benefit to the utility's customers This assumes the utility's financial integrity and health

3 DEVELOPING PRICING STRATEGIES

Strategic pricing requires innovation Innovation is a means to exploit change as an opportunity for a different business or a different service, Pricing, as a strategic response to change, requires utilities to search purposefully for opportunities that will benefit all ratepayers, whether they participate in the service offerings or not The following key questions direct the development of a pricing strategy

- How do costs vary for different types, quality, and characteristics of service?
- What conditions underlie change?
- What programs or services will achieve the desired results?
- What kinds of services or programs do customers want?
- How can utilities demonstrate the effectiveness of the programs?
- What is required to implement the programs or services effectively?

A systematic review of these questions provides the basis for strategic pricing This approach changes the focus of pricing functions from traditional costing methods and a concern about regulatory responses to flexible costing methods that are responsive to market conditions

The next chapters we will discuss rate structures providing examples of strategic, objective-based pricing, illustrating cost-based and market-based incentives

III Rate Design

Rate design evaluation is best performed by making the rate objectives explicit developing criteria to measure the rate's impacts on each objective, and assessing these impacts This chapter provides specific examples of the development of rate design strategies It covers blocked rates, time-of-use rates and incentive rates Blocked rates have long been used as a strategy to bring rate levels inline with the utility's marginal cost, promote the use of certain types of appliances or promote the adoption of energy conservation devices Time-of-use rates are being implement at an increasing number of utilities They provide a means of both bringing rates in line with costs as well as providing utility customers the incentives to manage their use in a manner consistent with the utilities' load shape objectives Incentive payment are a means of promoting utility objectives without necessarily having to develop new rate structures Thus, the utility can influence the effective price that a customer pays for electricity through the incentive design rather than having to change rates Often this can represent a significant advantage over tariff changes because of the regulatory and procedural requirements associated with rate change

1 Blocked Rates

A general service rate applies to a wide range of customers The individual customers served under a single rate differ in their total consumption, load factor, and distribution of use over the hours of the day and month Blocked rates, which have a long history in retail rate design, allow a rate schedule to include different prices for different customer subgroups The different prices reflect differences in costs imposed on the system by the subgroups For an illustrative example on how subgroups impose different costs on the system see table [1]

The example shows that the costs of serving individual customers depend upon the pattern of customer loads This can occur even when the wholesale rates for demand and energy are flat Because of administrative and metering costs, charging each customer a separate rate to reflect actual system costs is not feasible A lower-cost option is the use of blocked rates Using blocked rates, the unit cost of consumption (either demand or energy) varies as use increases Blocked rates may be declining, inverted, or "U" shaped The blocks reflect differences in the cost of serving customer subgroups under the rate When considering the blocking of rates, the following questions arise

- When is blocking relevant?
- How are the number of blocks, block length, and block prices determined?
- What are the impacts of blocking on conservation?
- What are the impacts of changes in blocking on rate continuity and revenue stability?

The blocking of rates is advisable when separate subclasses of customers that impose significantly different costs on the system can be identified under a single rate For example, a utility may have two separate rates for residential service One applies to customers who do not have electric water and space heating, and the second applies to customers who have these appliances The utility could analyze load research data to evaluate the differences in load and cost characteristics between the two customer subgroups If the differences in loads are small or insignificant all customers could be placed on a single rate If the differences in costs are significant, and if the average consumption levels of the two subgroups are different then the utility could develop a single blocked rate The utility could structure the blocking to produce different unit prices to the subgroups, reflecting the different unit costs of service

Utilities can develop blocked rates based on accounting or marginal cost of service In either case, the basic procedure is as follows

- Estimate unite demand, energy, and customer costs
- Isolate customer subgroups and estimate the load characteristics of each subgroup
- Apply unit costs to subclass loads to determine the unit cost of providing service to each subgroup
- Evaluate the differences in cost by subgroups to determine whether blocking is warranted

EXAMPLE OF COST DIFFERENCES BASED ON COINCIDENT (CP) AND NON-COINCIDENT PEAK (NCP) RESPONSIBILITY

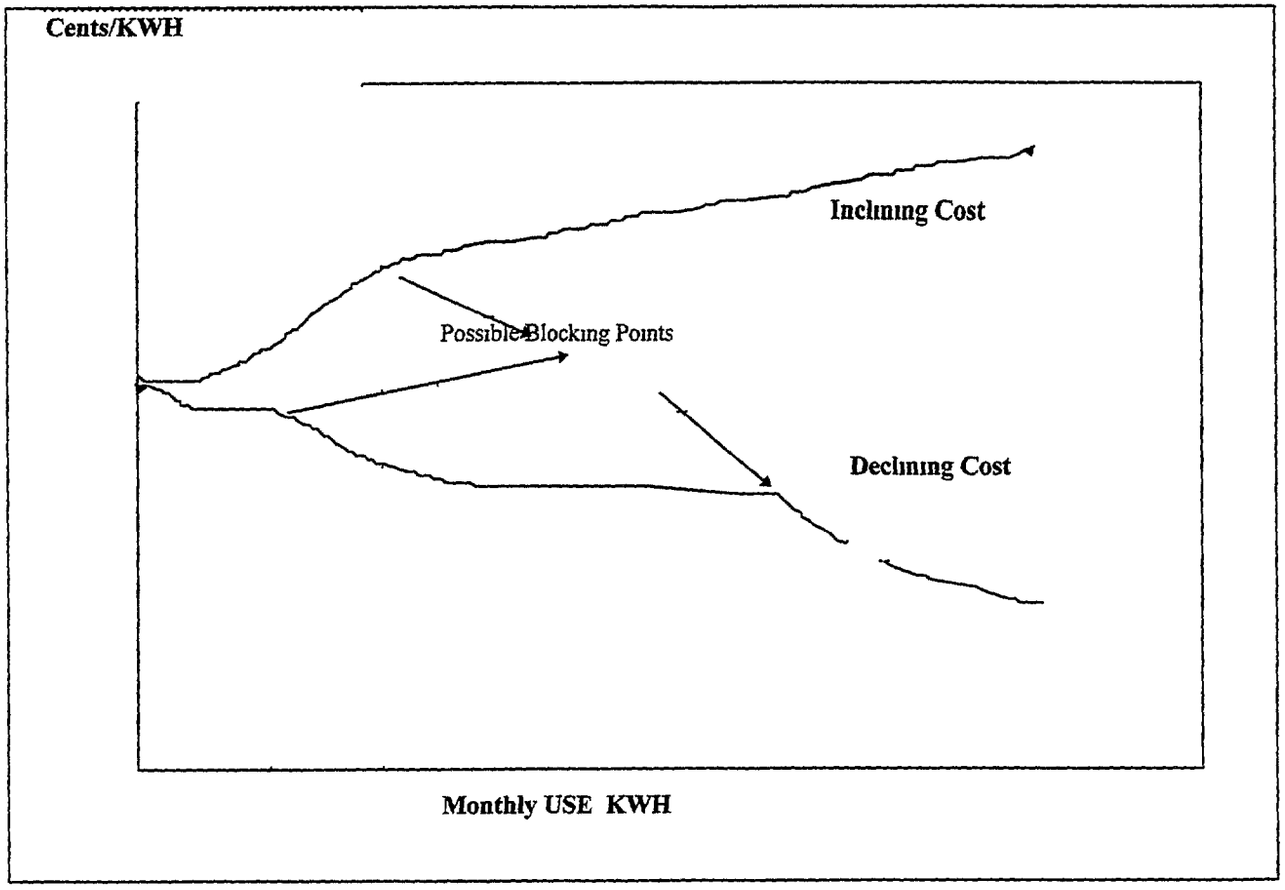
Marginal Demand Cost = $6/KW/Month of Coincident Peak Demand

Marginal Energy Cost = $0 04/KWH

		Customer 1	Customer 2
Energy Consumption/ Month	(kWh)	800	1600
Customer Peak Demand (NCP)	(kW)	4	8
Customer Demand (CP)	(kW)	2	3
Cost Imposed by Customer			
Energy ($0 04 X kWh)		$32	$64
Demand ($6 X kW CP)		$12	$18
Total Cost		$44	$82
Unit Cost (Total Cost/kWh)		$0 055	$0 0513

(Total costs excludes cost of distribution and losses in distributing power)

Figure [2] Blocking Points



2 Inverted Blocked Rates (blocking for conservation)

Many utilities system's marginal costs exceed their average system cost For these systems, the prices customers pay for increased use are less than the cost of providing additional electricity Utilities often invert the structure of rates to address this problem, setting prices for tail usage at or near marginal cost. In order to hold total class revenues constant utilities reduce prices for initial usage blocks The inversion of the rate is a vehicle for incorporating marginal cost signals into the retail rate Tow issues must be addressed when considering inverted rates

- Are inverted rates cost based?
- What will the impact of inverted rates be on class usage?

The situation where a utility's marginal cost of providing electricity exceeds its average cost does not necessarily imply that inverted rates are cost based For a simplified rate class with two types of customers

an inverted rate raises rates to larger users within the class and lowers rates to smaller customers Before implementing such a rate, the analyst must determine whether the use patterns of the two customer subgroups and the system's costs suggest this change in rates

3 Time-Of-Use Rates

For many utilities marginal and accounting costs vary over the hours of the day as well as the time of month and year The need for rates that vary accordingly depends on the degree of variation in system cost by season and/or the time of day A wide range of rate forms can be characterized as time-of-use (TOU) rates The development of TOU rates involves the following steps

1 Selecting costing periods

2 Attributing cost to costing periods

3 Converting costs into rates

The development of marginal cost-based TOU includes the following steps

- **Select rating periods** The costing periods developed during the estimation of marginal costs may not be appropriate for ratemaking Analysts developed these costing periods before estimating time-varying costs The rating periods are the hours to which a rate applies The primary objective of a TOU rate program is to improve the extent to which rate structure reflect underlying costs of production A secondary objective is to encourage customers to shift load from high-cost periods to low-cost periods This incentive to shift load should be tempered by efficiency and equity considerations

- **Convert marginal capacity costs to marginal demand charges** Although the terms marginal capacity cost" and "marginal demand cost" are sometimes used interchangeably, they are not equivalent The marginal Capacity cost is the cost of an increment of capacity needed (plus reserve) to maintain reliability when system peak load grows The marginal demand cost is the change in capacity costs associated with an increase in demand The marginal capacity costs must be converted to marginal demand costs for rate design purposes

- **Develop billing units and unit costs for demand, energy, and customer components** The next step is to develop costs that apply to readily available billing data Marginal demand costs are expressed in units of dollars per kW of demand coincident with the system peak However this is not the unit by which customers are billed for demand Rather they are billed for the maximum demand recorded at the customer's meter Since measuring demands for each customer coincident with the system peak is impractical the marginal demand costs must be expressed in terms of available data (i e , billing demand) Customers are metered and billed on the basis of non-coincident demand This demand will recover more than the cost of the

demands imposed on the system Thus, a mechanism is needed to relate coincident kW to non-coincident kW One way to do this is to calculate class coincidence factors For each class, analysts calculate the sum of the customers' monthly non-coincident demands in each billing period Adding these yields total billing units for the rating periods Similarly, analysts calculate the class coincident peak demand within each period The class coincidence factor is the ratio of coincident peak to the sum of the class non-coincident peaks

- **Assess adequacy of revenues** The marginal energy cost, and demand cost per KW of billing demand is a preliminary rate form The next step is to calculate the revenues that would result from these preliminary rates Analysts calculate these by multiplying each charge by the associated total billing units and summing all the elements

- **Reconcile revenues** The development of TOU rates based on marginal cost has proceeded independent of any established level of revenue to be collected from the class Analysts establish the required level of revenue by estimating the cost of providing service, including an operating margin for unforeseen circumstances and the coverage of interest payments Except for unusual coincidences the revenue collected with rates set equal to marginal costs will not equal the required revenue level Therefore analysts must adjust the rates to yield the required revenues This adjustment process is called revenue reconciliation The guiding principle to use when performing revenue reconciliation is to cause the least possible harm to the efficiency of the marginal cost prices

IV Estimating Marginal Distribution Costs

This section reviews the calculation of marginal costs for electric "distribution" utilities The estimation of marginal distribution cost is only discussed in this section For discussion about Generation and transmission marginal costs estimation see J H Chamberlin et al , "Costs and rates Workbook, part I, EPRI RDS #93A Sep 1981" Marginal distribution costs consist of customer-related and demand-related costs Customer-related costs are the increased distribution system costs that would be incurred to connect another customer to the system, but not to provide that customer with power Demand-related capacity costs, in contrast, are the increased distribution system costs of providing a customer an additional Kilowatt of capacity at the time of the distribution system's peak demand, assuming that the customer is already connected to the system Marginal costs also vary by primary and secondary delivery voltage customers Generally, utilities serve residential small commercial, and street lighting at the secondary voltage level Primary voltage customers are usually large commercial and small industrial customers Utilities serve large industrial at transmission system voltage levels, these customers have no demand-related marginal distribution costs

(a) Marginal Distribution Customer-Related Costs

There are three methods for determining marginal distribution customer-related costs, each of which defines marginal customer costs slightly differently because the distinction between customer- and demand-related costs is not always clear For example, a customer's metering cost is customer related However the size of capacity of the meter is determined by the customer's maximum demand so some of the metering cost is demand related The three methods are discussed in the following order

- Minimum system method
- Zero-intercept method
- Engineering approach

Minimum System Method

The minimum system method estimates customer costs by quantifying the cost of constructing a system to serve customers with minimum demand The application of this method for estimating marginal customer costs is similar to the minimum system method for embedded costs The following general steps comprise this method

- Determining the minimum-size equipment currently installed (i e minimum pole height conductor size, transformer size, service length, and so on)

- Multiply the minimum-sized equipment by the amount of total capacity (i e , number of poles, circuit miles, number of transformers, number of services, and so on)
- Multiply the average embedded installed cost of the facilities by the result of step 2
- The resultant costs are customer related The difference between the embedded distribution plant and the customer-related portion are demand-related costs
- Unitize the customer-related costs

To the extent that components differ in size or type by delivery voltage, the calculations should be carried out at as many different voltage level as data permit When using the minimum system approach for marginal costing, the first two steps and the final step remain unchanged However, in the minimum system approach, step 3 multiplies the result of step 2 by the current or expected installed cost (to maintain the forward looking emphasis) In this step, the analyst must adjust the cost estimate to the proper base year dollars using the appropriate price index Step 4 is eliminated because the minimum system costs do not affect the calculation of demand-related costs In summary, the minimum system method, when used to estimate marginal costs for each voltage level, is as follows

- Determine the minimum size equipment currently being installed (i e , minimum pole height, conductor size, transformer size service length, and so on)
- Multiply the minimum-sized equipment by the amount of total capacity (i e , number of poles circuit miles number of transformers number of services, and so on)
- Multiply by the current or expected installed cost
- Unitize the customer-related marginal costs, dividing them by the number of customers served by that portion or voltage level of the distribution system

zero-intercept method

The zero-intercept method for marginal costing is also similar to the zero-intercept method for embedded costs This method estimates the customer-related investment by first estimating distribution investment as a function of load and then extrapolating to zero load The definition of customer costs is slightly different from that for that the minimum system method Marginal customer costs in the zero-intercept method include only investments costs of no-load customers, while the minimum system method includes costs for minimum-load customers

In application, the zero-intercept method for marginal costing has several differences from its application for embedded cost calculation When used to estimate marginal costs analyst implement this method at a

more aggregated level than when it is used for embedded costs It is less data intensive when applied at the aggregate level The method for embedded costs analyze unit costs as a function of unit capacity across capacity sizes for several distribution components The method for marginal costs analyzes distribution as a function of growth in peak load for one or more voltage levels Analysts perform the following steps when using this method for marginal costing

- Determine the analysis period
- Convert all distribution cost data, net of meters and services, to constant dollars
- separate distribution between primary and secondary voltages
- For each voltage analyzed, relate total distribution to peak load using a trend or regression analysis
- Extrapolate the trends to zero load , and read the zero load costs off the vertical axis
- Unitize the costs using the number of customers (primary and secondary)
- Add the costs of meters and services

The analysis period should be forward looking Since sufficient data are frequently unavailable, the analysis must usually include some historical data

The Engineering Approach

The engineering approach to estimating marginal customer costs splits the system between demand-related and customer-related investments As with the other two methods, utility-owned equipment on the customer's property, including service and metering equipment is customer related However the engineering approach assumes that average-length line extensions and average-capacity line transformers are also customer costs This method is less data intensive than the minimum system method It also always results in a nonnegative answer To implement this method the analyst obtains estimates of average meter and service-drop installed costs by customer classification Then the analyst estimates average-length line extension and average transformer costs from data on customer installations The analyst may disaggregate the costs beyond the customer class level to reflect different geographic conditions building code requirements and infrastructure growth in previously underdeveloped areas In performing this method, costs are automatically developed on a unitized basis will normally reflect current conditions and will be forward looking All costs must be converted to the proper base year dollars

(b) Marginal Distribution Demand-Related Costs

The method of estimating demand-related marginal distribution costs is computationally the same as the method for estimating marginal transmission capacity costs With two exceptions Rather than computing one aggregate cost estimate, this method desegregates estimates by major voltage level (primary and secondary) Second, this method estimates costs per Kilowatt of peak demand As with transmission costs, distribution is first analyzed over historical and projected periods The time span can be shorter because the construction of distribution facilities is smoother and more continuos A typical time span covers historical years and three projected years The next step is to classify the distribution plant into demand-related and non-demand related categories Third, analysts separate the demand-related distribution into primary and secondary voltages For historical data, the utility's embedded cost studies give breakdowns of primary and secondary demand-related distribution Next, analysts convert the costs to constant dollars using an appropriate price index The fourth step is to unitize the additions by voltage based on primary and secondary voltage load growth Note that, distribution peak demand at the secondary level is not necessarily coincident with demand at the primary level because the secondary and primary customers load characteristics are different Also, analysts must unitize based on peak load growth for which the investments were planned The steps in estimating marginal distribution costs are

- Determine the time span to be analyzed
- Classify distribution plant as either demand or customer related
- Separate the demand-related plant into primary and secondary levels
- Convert all investment to constant dollars
- Determine planned load growth at primary and secondary voltages
- Unitize the investment costs
- Annualized the unitized costs
- Add operation and maintenance costs

V Integration of Rate Design With Demand-Side Management

Many utilities throughout the United States have undertaken major Demand-Side management (DSM) program in the past decade These DSM programs encompass all efforts to influence the pattern and magnitude of customer load, including conservation, load management, and marketing programs

In general, it is useful to consider the following five broad categories of DSM programs

- Peak Clipping Programs that reduce load during the peak periods (air conditioning cycling)
- Valley filling Programs that increase sales during off-peak periods (off peak water heating)
- Peak shifting Programs that shift loads from peak periods to off-peak periods (thermal energy storage)
- Strategic conservation Programs that reduce consumption at all times
- Strategic load growth Programs that increase sales at all times

The rate structure can be DSM program by itself (e g , TOU rates) as well as influencing the attractiveness of other programs

Cost Effectiveness evaluation of DSM programs

The approach to cost-effectiveness analysis presented here is called a "marginal cost-based cost-effectiveness analysis" The approach relies on utility resource planning criteria to budget future expenditures for generation, transmission, and distribution facilities The resulting model uses marginal costs to evaluate the benefits of a new rate or DSM program

The benefits of a DSM program are the estimated revenue requirements savings in capacity and energy costs avoided by implementing or expanding the program Utilities calculate this as the reduction or shift in load resulting from the program, times the marginal costs that would have been imposed to meet the old load curve

The program costs include utility revenue requirements and (from the impact on rate level perspective) the revenue loss Revenue losses arise when program participants lower consumption or shift use Revenue losses must be recovered from all ratepayers in revised rates From the impact on rate level perspective, the overall costs of the program to ratepayers are greater than the program revenue requirements

Utilities measured cost effectiveness using a benefit-cost ratio To calculate this ratio utilities sum the costs and benefits of each program and divide total benefits by total costs A benefit-cost ratio greater than 1 0 indicates a cost-effective program To understand the relationships among rates and other DSM programs utilities perform a set of cost-effectiveness calculations In these utilities combine DSM programs of varying types and load shape impacts with different structures and evaluate them for cost effectiveness

Analysts make the following observations on DSM and rate structure

- The attractiveness of DSM programs varies with the rate structure, and vice versa When the rate structure is such that marginal consumption is priced above marginal cost, conservation or other programs that reduce loads are attractive When marginal consumption is priced below marginal cost programs that build load bring in more revenue than costs and are cost effective

- As rates approach marginal cost, DSM program benefits decrease Pricing can change customer loads When rates equal marginal cost, the benefit-cost ratio is zero because the change in revenue is identical to the change in cost resulting from the program There are at least two caveats to this conclusion First, marginal costs change over time, and it is not possible to know the exact value of these costs Thus, rates may never equal marginal costs exactly Second, rates may not equal marginal costs exactly because revenue reconciliation, volatili and similar problems Some economists advocate using DSM programs in co nction with marginal cost-based pricing For example, utilities could use direct load control program to reduce peaks when marginal cost rates rise to unacceptable levels

- Utilities can make DSM programs desirable by changing the rate structure

- To obtain the benefits of a cost-effective DSM program the utility must accept the undesirable aspects of a rate structure For example, an inverted rate helps make a valley filling program most cost effective but may also decrease the stability of revenues from year to year or be perceived as inequitable Thus, the cost effectiveness of DSM programs is not the only objecti e of planning and rate design However to obtain efficient programs, utilities must integrate rates and DSM program planning

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Public Utilities Reports
GUIDE

UTILITY RATES

"I must admit that I possess no instinct by which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision

Justice Jackson, dissenting, *Federal Power Commission v Hope Natural Gas Co* 1944

Historically, availability of utility service was regulated in many situations before lawmakers began regulating the rates for it With the beginning of utility service, utility owners could charge whatever they thought the customer would be willing to pay to receive any service at all One can conceive of utility service *without rate controls, but rate controls without service* would have no meaning at all

Rate regulation, therefore, came about as a natural result of service regulation Once recognized and established, rate regulation rapidly assumed the central position Because it is more complex and controversial than service regulation it occupies most of the time and attention of the regulatory commissions Much of the authority these agencies have had bestowed upon them by the lawmakers was added in order to make their authority over rates more effective

Chapter 21
Determining Revenue Requirements

One can look at a utility s rates from the consumer's viewpoint to obtain efficient service at the lowest charge which will support and promote good service One can also look at the same subject from the utility company's point of view which naturally emphasizes the need for sufficient revenues and profits to protect the investors and attract more investment needed to support and promote an efficient operation This includes, of course, the job security of utility employees But there is also a third way of looking at it—the overall public interest, such as that of the community or other areas it serves All three points of view must be considered in arriving at a rate for utility service

The objectives of rate regulation are usually expressed in laws passed by the legislatures which set up the commissions and define their powers Such laws generally state that rates must be "just and reasonable" and must not cause "undue discrimination" nor give unjust preference "

In talking about the "powers of the commissions and their "responsibility for the fixing of "reasonable rates," we must not forget that the initial responsibility for reasonable rates and rate making is on utility company management The commission s job is to monitor what management does about it In most instances, the company sets up the rate schedules for service charges After the original establishment of rates by utility management, it continues to be a primary responsibility of management to see that the utility s rates remain reasonable, and to make or propose such changes, from time to time, as may be necessary to keep them that way

Commissions generally act as an umpire with full authority to veto, change, or investigate the reasonableness of rates already in effect Commissions can initiate rate changes by requiring a utility to ***show cause*** why existing rates should continue or different rates should be instituted This can be done, of course, only after notice, hearings, and other procedures which test the reasonableness of the rate on their own merits After such proceedings are held, the commissions can take action on their own authority Finally, as discussed in previous chapters, there are provisions for appeal to the courts to check on the fairness of the commission action

Standards of a Reasonable Rate

The quest for a reasonable rate is an effort to find one that meets all three of the obligations already mentioned—to the consumer, to the utility, and to the public interest It is also a search which looks for ***standards*** or ***tests of reasonableness*** All this would not, of course, be necessary if utility rates or prices were determined on a competitive basis But completely free and competitive market conditions do not usually exist in the operation of public utilities Commissions have had to use special guides to measure the reasonableness of rates for public utility service

The question posed is deceptively simple How much total revenue should a utility be allowed to collect from its customers through the rates charged for its product or service? There are a number of standards available, some more useful than others cost of service, value of service, quality of service, comparative rates of other utilities, competitive rates, and general economic conditions

(1) ***Cost of service*** Cost of service is generally accepted as one, if not the most important, measure of reasonableness of a utility s rates The term "cost of service" encompasses many elements and is often regarded as the most pervasive basis for determining revenue requirements and rate structures There is generally agreement in principle by both commissions and courts as to what constitutes cost of service

(2) ***Value of service*** Just as cost of service is a measure of the reasonableness of the rate from the utility s standpoint, so also "value of service" is a measure of the same thing from the customer s viewpoint Value of service establishes a maximum level of reasonableness just as cost of service establishes a minimum level It is obvious that no one will pay more for a service than he considers it worth He will either do without it or look for some kind of substitute This basic principle has long been recognized by both courts and commissions But it is not a very easy measure to apply because it rests on the customer s own opinion of what the service is worth This can vary widely between customers, or classes of customers, and from time to time or place to place In other words, since "value of service can be related only to the specific rates paid by the customers of each class of service, it is difficult to apply a workable measure of the reasonableness of the general level of a utility s rates

This difficulty of application is the chief problem raised by value of service" as a practical rate standard Costs are definite They are ascertainable in dollars and cents Value of service," in

contrast, is so much a matter of customer opinion that the only situation in which we can be sure it is having a true effect is where the customer actually quits or threatens to quit taking service Such a limited application does not help very much in dealing with the overall problem of determining the reasonableness of a utility s rates

(3) ***Quality of service*** The present view of both commissions and courts is that a utility s obligation to provide adequate service is just as important as its right to charge a reasonable rate Thus, quality of service is usually accepted as a factor for regulatory consideration in determining whether a utility rate is reasonable

(4) ***Comparison of rates*** Charges for similar services by utilities operating in other cities or areas are sometimes presented as a measure of reasonableness of rates To be a valid measure, however, there must be a reasonable similarity in operating conditions among the several utilities whose rates are being compared The underlying cost factors, such as the size and volume of the utility operations, the price of fuel, taxes, payroll, and other expenses, would have to be similar, or at least differences would have to offset each other, in order to make a just comparison Such absolutely comparable conditions are virtually impossible to find and even reasonably similar conditions are difficult to establish Therefore, rate comparisons are seldom satisfactory as a basis for regulation

(5) ***Competitive service*** Competitive conditions have been suggested as a test of the reasonableness of utility rates Competition among utilities generally shows itself in the form of competition from a substitute service Gas may compete with electricity for some services Gas or electricity may compete with fuel oil as a source of power used by industry More recently both electric and gas utilities are seeing competition from independent power producers, cogenerators, and spot market gas But to use a competitive service standard would entail comparisons of entirely different kinds of service with different operating costs For this reason, cost of competitive service has not been used as a standard for measuring a utility company s rates on the basis of reasonableness

(6) ***Economic conditions*** Fluctuations in general business conditions affect utilities just as they do other businesses In some cases, a rise in operating costs is even more difficult for a utility While an unregulated business can raise its prices promptly to reflect changing operating costs, a regulated utility usually cannot do so without experiencing the delays of regulatory procedure Ordinarily, public utilities have fairly stable revenues and do not experience the effects of either depression

or inflation as promptly as other industries But, this only means there is a lag in either direction (up or down) during which a utility customer is likely to use about as much service even though his own income has either fallen off or increased Consequently, it is generally thought that changes in prices and business conditions become a valid measure of reasonableness only insofar as they are reflected in the utility s own costs of service

(7) ***History of the company*** The history of a particular utility company has some bearing on the reasonableness of its rates A company which has been conservatively managed and has shown regard for the public interest is much more likely to propose reasonable rates than will a company whose history shows the opposite conditions But the use of previous rates charged by a company would be a poor measure of their reasonableness even though voluntarily established by the company in view of changing costs and economic conditions

There have been other factors which commissions have considered in testing the reasonableness of rates Enough have been described, however, to show that there are various standards of reasonableness, and that the 'reasonableness of a rate is, in many respects, a matter of judgment based upon the relative importance of all the factors in a given case Out of experience, commissions have come to rely more heavily on cost of service than on any of the other tests of reasonableness of rates Value of service may also be used mainly as a check on the maximum level for rates It is often pointed out that cost of service sets a lower limit on rates, whereas value of service sets an upper limit Within these limits is a "zone of reasonableness" into which rates should fall and within which utility management should have leeway in determining the actual rate which it will charge for each of its various classes of service

The Test Period

A utility has a set of specific rates, called a ***tariff,*** on file with the commission These rates continue to be in effect until they are changed In recent years, utilities have been forced to revise their rates just to keep pace with changes in the cost of providing service The difficulty for utilities in pricing their services stems from the fact that rates are set prospectively That is, rates are set for services to be delivered in the future, not to recover the costs of services already rendered If a utility does not earn its authorized earnings in one year, it cannot make up that loss Its only recourse is to ask the commission to approve higher rates If the commission agrees, increased rates will be granted—but only for the following year Most states do not allow retroactive ratemaking,

that is, the establishment of rates which can be applied to service already rendered

21 Assume for a moment that a utility did not make enough money in 1991 to recover costs In April, 1992, it approaches the commission and files for a rate increase It may take a commission several months to decide on a rate adjustment, so the revised rates will probably not take effect until sometime in 1993 (the "rate year") How can the parties know what a "just and reasonable rate will be in 1993? The loss in 1991 does not really matter, the issue is whether there will be a loss in 1993 or, more precisely, what the revenue requirement for 1993 should be

In determining a utility's rates, a ***test period*** (also referred to as a test year) is selected and used as a proxy for the future This method has its flaws In times of inflation, test-year prices will be lower than actual prices during the year the rates will be in effect Test-year prices, however, are known and certain and provide a starting point for the rate determination

In the previous example, the test year might have been calendar year 1991 (The test year is often the most recent calendar year for which data are available) Considering the fact that the test period is only a proxy for the future, the utility will not necessarily prove its need for higher rates just because it did not earn enough revenue in calendar year 1991 Commissions, wanting to know what is likely to happen in the rate year, will use the test period as a guide But should the test period be abnormal for some reason, the commission will make adjustments This process of making the test period representative of the average operations of the utility is known as ***normalizing*** the test period

Normalization adjustments can be made for many reasons If sales were low for some reason—*e g* , gas sales were off because the winter was mild—the commission may make an adjustment and impute some additional sales to the utility Test periods are also normalized to reflect "known and measurable changes In our example, assume that the utility granted its employees a wage increase in December 1991, the last month of the test period Test-year wage expense would reflect eleven months at the lower rate and only one month at the higher rate—even though the higher rate is likely to be in effect for the full twelve months of the rate year To remedy this flaw, the test year is normally recalculated at the higher wage rate

Alternatively, some commissions have determined that the use of an historic test period is unsatisfactory in times of rapidly changing prices Several options have been tried Many jurisdictions use a year-end test period (in our example, December 31,

1991) This approach narrows the gap between the data used to determine rates and their implementation A forecasted or partially forecasted test period involves the use of estimated data In the example above, a typical partially forecasted test period would combine actual results from July-December of 1991 with estimates for the January-June, 1992, period

The Revenue Requirements Formula

Determining a utility's revenue requirements is one of the first major steps in developing utility rates Recall the simple revenue requirements formula presented in Chapter 13

$$RR = O + T + D + r\,(RB)$$

where RR = revenue requirement
O = operating costs
T = taxes
D = depreciation allowance
r = a fair rate of return
RB = rate base

Assume that a utility has a rate base of $10,000,000 (the amount invested in facilities needed in order to produce service) and the commission determines that investors are entitled to earn a 12 percent return on the capital they invested in the company Further, assume that operating costs, together with an allowance for depreciation and taxes, total $2,500,000 Substituting for the variables in the equation, one can derive the utility's revenue requirement

$$\begin{aligned} RR &= \$2{,}500{,}000 + 12\%\ (\$10{,}000{,}000) \\ &= \$2{,}500{,}000 + \$1{,}200{,}000 \\ &= \$3{,}700{,}000 \end{aligned}$$

In order to perform the second half of the rate-making process (rate design) it is necessary to estimate the sales of the company By dividing the total revenue required by the total units of service (cubic feet of gas or kilowatt-hours of electricity) used by the customers, the revenue requirement or rate for each unit of service is indicated This bare explanation oversimplifies the operation because it does not allow for such variations as classes of service, volume of use or load conditions under which the units are used But disregarding, for the present, such refinements, this simple explanation will give one a very general idea of the guiding principle which are called for in fixing utility rates, so as to make them meet the standard of reasonableness described above

Continuing with our example, assume that the utility will sell 53,000,000 units and that it is desirable to charge all customers at the same rate Dividing the revenue requirement ($3,700,000) by

the number of units to be sold (53,000,000) yields the just and reasonable rate of seven cents per unit

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Rate of Return

In earlier chapters, we have taken a close look at most of the components of the revenue requirements formula operating costs, taxes, depreciation, and valuation of rate base Determining a rate of return on the utility s investment is the final step in setting the overall revenue requirement While setting the return is often the most complicated—and controversial—part of a rate proceeding the general theory is rather simple

A public utility's return is comparable to the profits of an unregulated business The rate of return, expressed in percentage form and applied to a utility s rate base, is a regulatory concept designed to produce a dollar amount which will yield sufficient revenue to pay the utility's investors for the use of their money Bondholders expect to receive their interest payments and stockholders also want to be compensated Thus, a fair return is one which will enable the utility to meet these obligations and be able to continue to attract capital

Unlike consideration of rate base and operating expense issues, which are usually concrete, the setting of a fair rate of return is amorphous and subjective There is no single, scientifically correct method for fixing the proper return Instead, the Supreme Court has held that commissions must set a return which is within a zone of reasonableness " This zone will vary from utility to utility depending on the individual circumstances of each case The return may not be so low as to impair the utility s ability to attract capital, nor may it be so high as to be unreasonable considering the comparative earnings of similar investments involving comparable risk It is within this zone that commission discretion concerning the proper rate of return is exercised

Weighted Cost of Capital

Consistent with the "zone of reasonableness" mandated by the Supreme Court, commissions have tended to use the company s ***cost of capital*** as the basic standard of a fair rate of return There is thus a close association between a fair rate of return and cost of capital Given this standard, the determination of a ***fair return*** is a matter of determining the weighted cost of each form of financing That weighted cost is the cost of each form of financing times its proportion in the capital structure Return times rate base produces "fair return on rate base "

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For example, assume that a utility has a total capitalization of $1 million which is made up of $500,000 of 10 percent bonds and $500,000 of equity Assume further that the cost of equity is 12 per cent Then

	Amount	x Cost	= Weighted Cost of Capital
Debt	$ 500,000	x 10%	= $50,000
Equity	500,000	x 12%	= 60,000
	$1,000,000		$110,000

The weighted cost of capital, in this example $110,000, is equal to the fair return which the utility would expect for its investors Dividing that cost of capital by rate base would yield the rate of return expected $110 000/$1 000,000 = 11% The 11 percent rate would be applied to rate base in order to determine the fair return component of the revenue requirement

A second example serves to illustrate what happens to that fair return figure if the mix of securities in the capital structure changes Assume that the utility reduces the equity component to $400,000 and increases debt to $600,000 The calculations then appear as follows

	Amount	x Cost	= Weighted Cost of Capital
Debt	$ 600,000	x 10%	= $60,000
Equity	400,000	x 12%	= 48,000
	$1,000,000		$108,000
Fair rate of return = 10.8%			

In reality, the calculation is considerably more complicated Determining the cost of debt, however, is fairly straightforward The cost of short-term debt (funds borrowed through bank lines of credit, for example) is readily ascertainable Similarly, the cost of long-term debt is simply the coupon rate of the bond (10 percent in the example above) Determination of the cost of equity, however, is the central problem in rate-of return analysis

Significance of the Rate of Return

Prior to the 1950s, courts and commissions paid far more attention to the value of the utility's physical property and the related dollar amounts than to the percentage allowance for rate of return

This may seem surprising in light of the fact that even a slight variation in the rate of return weighs far more heavily than a variation in rate base valuation The former is more sensitive and far-reaching A difference, up or down, of only one percent in the rate of return could have about the same effect on rates as an increase or reduction of 12 to 15 percent of the rate base allowance

Assume, for example, that a utility has a property fairly valued and adjusted to indicate a rate base of $10 million, and that its operating expenses, including taxes and depreciation, are $2 5 million a year Next, assume that an 11 percent rate of return on the property value, or rate base, of $10 million is found to be fair and reasonable This would result in a dollar amount of return of $1 1 million on such a rate base It also means that the charges for service would have to produce a revenue requirement of $3 6 million a year, to cover the expenses ($2 5 million) plus the amount of return allowed ($1 1 million)

Now suppose that the utility claims it is entitled to charge more because its rate of return was fixed too low If the regulatory commission approves, to the extent of increasing the rate of return from 11 percent to 12 percent (and the operating expenses remain the same), then the rates charged for service will have to be increased to the point where they will produce $3 7 million in yearly revenues, so as to cover expenses ($2 5 million) plus the higher amount of return allowed ($1 2 million)

But suppose, instead of asking for a higher return allowance, the utility company claims that its rate base of $10 million was fixed too low How much of a boost in the rate base would yield the same end result? If the original 11 percent rate of return were still used, it would take an addition of $909,090 or about a 9 09 percent increase (bringing the rate base to $10,909,090), in order to yield a dollar amount of return (or $3 7 million) equal to the result in the previous paragraph (assuming, for simplicity, that taxes remain constant) Thus rates for service may be raised or lowered by changes in the rate base (property valuation) as well as by specifying the rate of return (percentage allowed on the rate base)

Rate Base	$10,000,000	$10,909,090
Rate of Return	x 12%	x 11%
Return	$ 1,200,000	$1,200,000
Expenses	$ 2,500,000	2,500,000
Total Revenue Requirement	$3,700,000	[illegible]

The rate of return has received as much or more scrutiny than the rate base in contested rate cases The return allowance is likely to receive extended consideration through expert testimony and regulatory analysis While we will consider the generally accepted indicia of a fair return, the reader is cautioned that the rules, while fairly easy to state, are extremely difficult to apply in the context of an actual rate case

The Cost of Debt

Analysts usually have no difficulty in computing the cost of ***senior capital*** (long-term debt and preferred stock) with precision Actual fixed charges such as interest and preferred dividend payments represent the annual cost in dollars There is some debate, however, with regard to the issue of short-term debt Short term debt is frequently used as bridge financing ' Construction is financed with short term debt until it accumulates to an amount sufficient to justify a bond issue, then is converted into permanent financing

Some commissions include short-term debt in the capital structure, others do not The impact on the weighted average cost of capital is usually minimal If short-term debt is included, it is usually carried at its current cost rate

Determining Cost of Equity

What is the cost of equity? In answer to that query, a parallel question might be posed How much of a return do investors require in order to hold a utility's stock? This is a highly judgmental area which is subject to considerable dispute

Based on two landmark U S Supreme Court cases in 1923 and 1944, two principles have emerged with respect to fairness in determining the cost of equity These are the standards of ***comparable earnings*** and ***capital attraction*** Both involve what is known as ***opportunity cost*** Investors, by making the decision to invest in the equity of a utility forego the opportunity to invest elsewhere Accordingly, investors should be compensated such that their expected return on a utility s equity is equal to the returns they could expect on an investment of comparable risk elsewhere in the economy Although there are no guarantees that the utility will earn that return, the company should be provided with the opportunity to earn a level sufficient to continue to attract investors Some of the more frequently used methods for determining the cost of equity are discussed below

Discounted Cash Flow One popular approach to determining the cost of equity capital is the discounted cash-flow (DCF) method This approach assumes that the price of a stock is the present value of the income to be received from it in the future The present value of the stock is measured by the expected future benefits the dividends to be paid and the proceeds from the ultimate sale of the stock The expected return is the sum of dividend payments plus some measure of growth in value This is the most commonly used formula to determine the cost of equity

The basic assumption underlying the method is that the price an investor pays for a share of stock represents the ***present value*** of his anticipated future cash flow from dividends and price appreciation at his required rate of return Since dollars to be received in the future are not worth as much as dollars received today, the *cash flows* must be *discounted* back to the present at the investor's required rate of return

This present value has two components the yield for dividends over time (yield) and the increase in value of the company ("growth") Discounted cash flow analysis estimates these values and derives the current value of the stock The most common expression of the basic formula is

$$K = \frac{D}{P} + G$$

where

K = current cost of equity
D = dividend rate
P = market price, and
G = growth rate

Another variation of the basic DCF model is a model which takes into account the fact that dividend payments usually are received four times a year rather than only once as assumed in the annual version of the model The purpose of this quarterly model is to take into account the possibility of reinvesting the dividends for part of the year That formula is as follows

$$K = \frac{D}{P}(1 + G) + G$$

A third form of the basic DCF model is one which relaxes the assumption that the growth rate be constant It may be assumed that the growth in dividends will be at one rate for a few years, and then, at another rate in perpetuity This model is more complicated, and the issue of growth rate of dividends remains somewhat controversial The very characteristic of DCF analysis which makes it so attractive—its prospective gauge of the market—is also its most serious problem Gauging investor expectations is no small feat Use of the formula requires the analyst to assign a quantitative value to a nebulous feeling

Risk Premium Approach This is perhaps the second most popular approach for estimating the cost of equity The premise underlying the various techniques used in this approach is that the required rate of return is higher for riskier securities than for less risky securities Thus, equity has a higher required return than debt The difference between the cost of equity and debt is the required premium for enticing investors to accept the greater risk associated with equity The cost of equity is estimated using this basic formula

$$k = k_d + RP$$

where k is the required return on equity, k_d is the long term cost of debt and RP is the risk premium

This risk premium method appears simple, but, like other approaches, there are measurement problems, associated with implementing the technique For example, risk premiums do change over time and premiums based on historical averages fail to account for changes in the riskiness of debt versus equity To avoid such problems, a technique which estimates expected premiums has been utilized Basically, this estimates the risk premium based on the DCF approach Thus, the quality of such estimates is again dependent on the quality of the DCF estimates

Comparable Earnings Method The basis of this method is the economist's concept of opportunity cost Typically, in applying the comparable earnings test, an analyst selects a sample of companies—utilities or nonregulated firms—considered to be comparable in riskiness to the utility being analyzed The reasonableness of the rate of return may be measured by comparison of the utility company's earnings with those of the other enterprises The validity of such comparisons hinges upon similarity of the degrees of risk involved, whether there is any competition in any of the cases compared, or upon similarity of economic conditions under which the companies are operating Because closely comparable conditions are difficult to find and establish, commissions as well as the courts tend to use this measure as a check against a rate of return, rather than as a decisive test in itself

Capital Asset Pricing Method The capital asset pricing model, or CAPM, is a financial model which assumes that investors hold stocks in portfolios, or groups The risk of a portfolio is less than the risk of the individual stock as a result of

diversification The overall risk of a stock is thus divided into two parts the specific risk unique to a company, and general market risk Because investors, through their choice of portfolio holdings, can diversify away company specific risk, the CAPM method holds that they should not be rewarded for bearing this type of risk They do, however, bear a market risk CAPM suggests that the cost of equity is the sum of a risk-free rate of return plus a return to compensate investors for market risk This measure of market risk is called ***beta*** Beta captures the extent to which a stock s return moves with market returns Simply explained, the historical returns of a stock are compared with the returns of the market If the stock's returns are more volatile than that of the market, the stock is regarded as above average risk Beta provides a way of adjusting the market premium to account for the riskiness of an individual stock

A full description of the model is beyond the scope of this course, but this general explanation should provide the reader with a basic understanding of its operation In principle, the beta should be forward looking In practice, however, the beta used to implement the CAPM is an historical beta

Estimating Growth

One factor which is an inherent part of each of the methods described above is the growth of the utility and the growth in the value of its stock, especially as perceived by investors This factor is incapable of being objectively quantified Current dividend yields and the price of the stock are usually objectively ascertainable and, generally, subject to verification The expected rate of growth of the company, however, is subject to dispute It is important to note that the actual growth rate is irrelevant Analysts seek to determine what investors anticipate the growth to be, since it is investors anticipations which will determine the cost of the stock

Three measures are commonly used anticipated growth in dividends per share, earnings per share, or book value per share There is substantial disagreement over the accuracy of these factors, commissions often differ as to which best estimates anticipated *future* growth Since investor-anticipated growth is the variable to be estimated, an argument for acceptance of widely used investment data (with their attendant savings in time and energy) can be made

Selection of the proper indicator of growth does not end the analyst s task Appreciation, as measured by that standard, must also be determined Simple arithmetic extrapolation is the readily

apparent solution, though few would contend that this is likely to be a highly accurate estimate of future growth

The methodology for determining a utility's rate of return on common equity is at an interesting juncture While the acceptance and use of discounted cash-flow analysis is an improvement over earlier intuitive approaches, it still presents problems The determination of a proper return necessarily requires consideration of factors which cannot be easily quantified

Is Rate of Return Guaranteed?

There is a popular misconception about utility return that should be dispelled Many people assume that when a commission finds that a utility company should be allowed a given rate of return, that company is thereby automatically guaranteed that it will get that return This is far from true All the commission has decided, in such a case, is that the utility can charge such rates as will permit it to earn the allowed rate of return—provided, of course, the volume of business is sufficient to yield the allowed amount But the utility has to earn it, and it does not always follow that the utility will do so

Conditions may be such that the allowed rate cannot be earned An unexpected natural catastrophe, such as fire or hurricane loss, may cause such an increase in operating expenses that they equal or exceed revenues A decline in business activity may be accompanied by a decline in sales of service and revenues therefrom so that net earnings are reduced or wiped out Shifts in industry location and population may cause a community to decrease in size with consequent adverse effect on utility earnings in that community In other words, a commission's allowance of a stated rate of return is not a guarantee It is more in the nature of a fishing or hunting license When you get such a license from the state or county, there is no guarantee that you will get fish or game It merely makes it legal for you to obtain such benefits, if you can do so by your own efforts There may also be a limit on how much fish or game you can take The same limit applies to the return allowance of the utility

There is one other concept which should be mentioned before closing the discussion of return In fixing rates for utility service, commissions must look to the present and the future The level of rates to be determined is for today and tomorrow—not yesterday The prospective nature of return is a two-edged sword Just as utilities are entitled to a return based on future needs, they are prevented from earning a return designed to remedy past problems

Review Questions

1 What does beta measure according to the capital asset pricing model? _____

_____

2 What is the weighted cost of capital for a firm whose capital structure is comprised of $400,000 of 11% equity and $200,000 of 10% debt? _____

_____

3 What is meant by the term 'test period' and how is it applied in determining a utility's rates? _____

_____

4 What is meant by 'normalizing' the test period?

_____

_____

5 Why are expected earnings discounted under the discounted cash flow method of determining cost of equity?

_____

_____

Chapter 22
Principles of Rate Design

Once the determination of appropriate revenue levels for a utility been made, the question of how to allocate those allowable costs among a utility's customers must be addressed. Utilities have long experimented with the proper method of charging their customers for service. The issue—how to recover the costs of service from those responsible—is deceptively simple. A utility company desires not only to secure rates that will yield the approved fair rate of return, but to develop a pattern of rates that will promote growth of earnings and that will protect these earnings against adverse business conditions.

There are many criteria which are employed by commissions in evaluating various rate designs. Among the issues which are considered by regulators are the following:

- Cost of service
- Value of service
- Constraints of revenue requirement
- Avoidance of unreasonable discrimination
- Rate structure continuity
- Appropriate rate relationships
- Ease of understanding and administration
- Customer impact
- Competitive impact
- Incentives for promotion of efficient use of service

Examination of this list lends support to the proposition that rate design is more an art than a science. Some criteria may be more important than others in certain cases. This is not an exhaustive list. Several of the items mentioned are, however, major considerations in rate design theory.

Differential Rate Making

It has long been a fundamental principle of utility rate making that customers receiving the same kind of service under the

same cost conditions should be charged the same rate Indeed, the prevention of undue discrimination has been a goal of regulation since its inception

It is important to note that only *undue* discrimination is proscribed Generally speaking, rate discrimination is unfair and therefore unlawful in three situations (1) where two customers are charged different prices for what is essentially the same service, (2) where two customers have to pay the same price for essentially different services, but one derives a greater advantage than the other, and (3) where the difference in rates is greater or less than the cost of service differences involved in the special circumstances or conditions for both customers

Customers receiving service under different conditions should reasonably be expected to pay the cost of providing their particular service This distribution of rates on the basis of different characteristics of service cost and usage is known as ***differential pricing***

Differential pricing is practiced in order that the utility s rates may not only recover the total cost of providing the service but also apportion those costs, as closely as possible, to the parties responsible for incurring them Rate structures are designed to reflect these differences in costs The classification of customers is a compromise between having one set of rates for everyone and individual tariffs for each customer Figures 22-1 and 22 2 indicate the importance of classification to rate design

Figure 22-1

TOTAL ELECTRIC UTILITY INDUSTRY

1990

Class	% of Total Customers	% of Total Revenues
Residential	88.2	40.7
Commercial	11.0	30.7
Industrial	0.5	25.3
Other	0.3	3.3
Total	100.0	100.0

Source: Edison Electric Institute

Comparing the figures in the two columns we see that almost nine out of ten customers took residential electric service and contributed just 40 percent of total revenues Commercial and industrial customers, although accounting for groups of significantly smaller size, contributed substantial levels of revenues Obviously, rate differentials played a large part in these proportions A similar situation prevails in the gas utility industry

The relationship between differential charging and generally lower rates should be clear from these figures In the gas and electric industries, the highest rate is usually charged for residential service Even so, it is the accepted opinion that residential rates are lower—substantially lower—than they would be if it were not for the commercial and industrial business It is important to note that all customers may benefit when a utility offers a lower rate to a class of customers for which it is justified This result—which may run counter to intuition—is obtained since the discriminatory rate may cause more customers to consume, which in turn would result in more efficient utilization of capacity The price then charged for each class is lower than it would be otherwise

Figure 22-2

TOTAL GAS UTILITY INDUSTRY

1990

Class	% of Total Customers	% of Total Revenues
Residential	91.7	55.3
Commercial	7.8	23.5
Industrial	0.3	19.9
Other	0.2	1.3
Total	100.0	100.0

Source: American Gas Association

For example, assume that an electric utility initiated a discount rate for a class of use which was currently being satisfied by some other fuel Although the users that switched from the other fuel to electricity would be paying a lower rate than other customers, they would also be making a contribution to fixed costs Since those costs remain constant, as they are spread over more users, the portion to be borne by any one user declines In the past several years, both gas and electric utilities have initiated special rate programs for large industrial customers who have the capability to utilize other fuel sources When these rate programs succeed in keeping large customers on the system or in attracting new customers, these large volume customers keep the price of service lower for all customers These trends in rate design will be examined in greater detail in later chapters

It is important to note, however, that price discrimination will have this beneficial effect only in limited circumstances First, there must be a demand for both services at the different prices offered Otherwise, the customer would choose to slide over to the use with the lower price For price discrimination to be of benefit to the utility the utility must also have sufficient capacity so that constant fixed costs can be spread over a larger volume of output and the ability to attract new customers who would not otherwise utilize its service Finally, the discriminatory rate must be high enough to cover all the new variable costs and yet make some contribution to fixed costs

Different Types of Costs

There are several broad classifications of costs and different methods of recovering them These include

Customer costs—the fixed costs incurred in serving each customer (meter reading, billing, collecting, etc) The costs are approximately the same for all customers in each class Thus, they can be efficiently allocated by simply dividing the total by the number of customers

Energy costs—the variable costs connected with plant operation The major items included in these costs are plant expenses and fuel They are related to the quantity of output and therefore can be distributed to a given customer (regardless of the class of service) on the basis of the quantity of the service used—whether kilowatt hours, cubic feet of gas, or their equivalent in therms

Demand costs—those costs related to the investment in plant and facilities and the relative demand which a particular customer or class of customers may make upon the system s total capacity to serve They include consideration of the utility s responsibility to meet peak loads and are largely fixed in nature, covering such items as interest on borrowed funds, taxes, depreciation, and returns on equity capital which may be paid out as stock dividends or retained as earned surplus The sharing of these costs by the several classes of service, and by each customer within his or her class, is related to the kind of demand made on the service

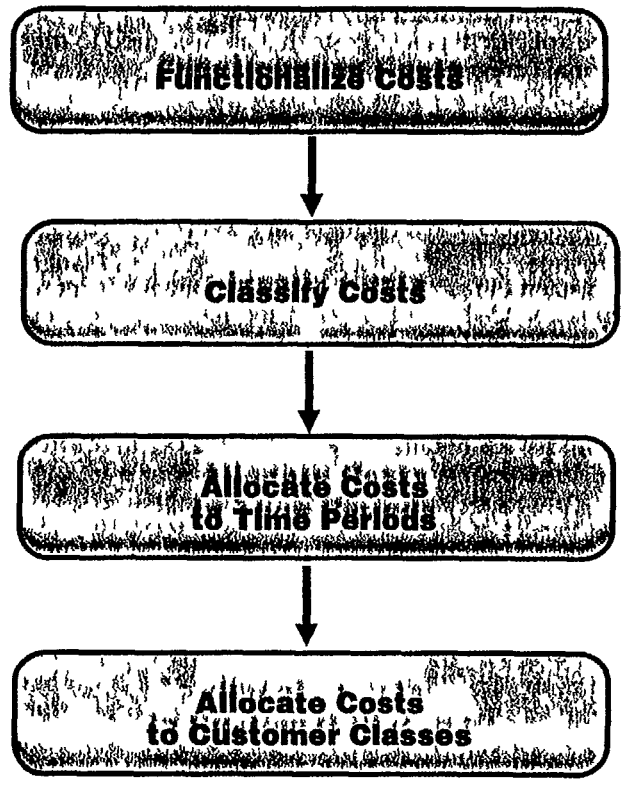
Overhead and administrative costs—the costs of the company's general office and management, such as the down town business headquarters and branch offices These costs are incurred on behalf of all company activities Some part of these costs should be assigned to customers, some to energy, and some to demand

Once overhead and administrative costs are distributed, we are left with the three classifications of costs mentioned above customer costs, energy costs, and demand costs

How are costs assigned to each class of customer? Cost-of-service studies developed by utilities allocate various utility costs to classes which are responsible for them The end result of the study will be the determination of the average cost per unit to the utility of supplying service to each class Rate cases often involve disputes between parties as to who should bear how much of certain common costs Public utility operations are outstanding examples of providing service under conditions of common costs, to be shared by different classes of customers The distribution of common costs to each class of service can involve some very technical challenges

Figure 22–3

STEPS IN COST ALLOCATION



Functionalizing Costs

Much progress has been made in an lizing the distribution of costs to various users of the service with a view to establishing the relationship of their responsibilities to such costs It is generally believed that a reasonably fair and satisfactory distribution can be made Even so, any distribution is necessarily based upon judgment If cost distributions are sufficiently close to measure approximate differences in costs, that is generally accepted as justification for differences in charges

No formula for cost distribution can be so precise as to reflect every factor to an exact degree There are, however, some generally accepted procedures for the assignment of costs to various classes of customers Figure 22 3 provides a brief outline of the process

Functionalization refers to the assignment of costs into the functional categories of production (or generation, the process of converting other forms of energy into the utility service), transmission, and distribution Figures 22 4 and 22-5 highlight some of the specific types of costs that assigned to these various functional categories

22–4
FUNCTIONALIZATION OF ELECTRIC COSTS

tion	Transmission	Distribution	General
iting Plant ition O&M ost sed Power	High Voltage Transmission Lines Transmission O&M Transmission Stations	Distribution Lines Distribution Substations Line Transformer Meters Service	Plant or expenses not related directly to other functions

22–5
FUNCTIONALIZATION OF GAS SYSTEM COSTS

ction	Storage	Transmission	Distribution	General
ne demand es ng facilities or LNG plant	Underground storage Local storage	High pressure long distance gas transportation	Transporting gas to ultimate customers	Plant or expenses not related to other functions

Classification refers to the assignment of co by energy usage, peak d and number of cu mers within the functional categories We previously referred to the various classifications of costs (demand, energy, and customer) Once costs are assigned to a function, they are also assigned a classification The grid in Figure 22-6 demonstrates how particular expenses may be functionalized and classified This is a crucial step in determining ultimate rate design

Figure 22–6

CLASSIFICATION OF COSTS

FUNCTION	Classification: Demand	Energy	Customer
Production	X	X	
Transmission	X		
Distribution	X		X
General			X

To assist utilities in the process of cost allocation, The National Association of Regulatory Utility Commissioners (NARUC) has published utility cost allocation manuals Using the Uniform System of Accounts, NARUC has issued guidelines for the assignment of accounts, specifying whether they are demand, energy, or customer-related Figure 22 7 provides a brief example

Allocating Costs Among Customer Classes

The allocation of costs to specific class s customers is the third step in the process of fully distributing the costs of service Preliminary to the allocation process is the need to define the various classes of customers Typical customer groups include, but are not limited to, the following

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- Residential—Individual and/or master meter
- Commercial, Small Light and Power
- Industrial, Large Light and Power
- Agriculture and Pumping
- Street Lighting (electricity)
- Transportation (natural gas)

22–7

CLASSIFICATION OF ELECTRIC RATE BASE

Uniform No.	Description	Demand Related	Energy Related	Customer Related
	Production Plant			
3	Intangible Plant	X	—	—
6	Steam Production	X	—	—
5	Nuclear Production	X	—	—
6	Hydraulic Production	X	X	—
6	Other Production	—	—	—
	Transmission Plant			
9	All Transmission Accounts	X	—	—
	Distribution Plant			
4	Land & Land Rights	X	—	X
4	Structures & Improvements	X	—	X
4	Station Equipment	X	—	—
4	Storage Battery Equipment	X	—	—
4	Poles, Towers, & Fixtures	X	—	X
4	Overhead Conductors & Devices	X	—	X
4	Underground Conductors & Devices	X	—	X
4	Line Transformers	X	—	X
4	Services	—	—	X
4	Meters	—	—	X
4	Installation on Customer Premises	—	—	X
4	Street Lighting & Signal Systems	—	—	—

Excerpted from NARUC, Electric Utility Cost Allocation Manual, 1973

While the issue of customer classification has arisen in some rate proceedings, the process is not an exact science, but is based on convenience as well as logic Commissions look to such considerations as the customer s location, load and diversity factors, voltage level required gas throughput, partial versus full service

requirements, various cost-causing factors, practicality, and common sense

With changes in the types of service being offered by today s electric and gas utilities (transmission and transportation, as well as full utility service), the need to develop sound allocation factors to spread costs between customer classes is more demanding today than it has ever been For example, when a gas utility is providing primarily only one service (such as the merchant function of the sale of gas), the demands of cost separation between different types of customers are not nearly as great as when the company maintains the dual role of merchant/transporter The very different types of service require differences in cost allocation The basis of cost allocation methodologies that were developed in some cases over 40 years ago must be revisited to ensure that the allocation of costs reflect today's markets and usage patterns

Marginal Cost Pricing

Although cost of service is the guiding principle of rate design not all rates are based strictly on ***embedded***, or incurred cost Operating under the traditional principle that rates as a whole should cover costs as a whole, ***marginal cost***, also known as ***incremental cost***, plays an important role in the design of rate structures Under the conditions of pure competition, price (which represents what consumers are willing to pay for the last unit consumed) is equal to the cost of producing that last unit, that is, marginal cost As a result, the consumer s valuation of the last unit and the cost of producing the last unit are equal This is basically the theory of marginal cost pricing for economic efficiency

Many attempts at rate reform focus on the technique of marginal cost pricing Though admittedly complex in application, its rationale is simple enough Each customer should pay the actual cost that his use of service imposes on the utility

Marginal cost pricing is based on the cost of service at the most recent or next immediately required plant The rate charged equals the cost of producing one more unit or the savings from producing one less unit The result is that the customer pays for what he consumes and conservation and efficient use of resources are encouraged

Although most economists agree on the theory, the practical feasibility of applying marginal cost principles to utilities is difficult Utilities are very complex and make varying investments and expenditures to provide a variety of functions, *e g* , generation,

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transmission, distribution, and ser[illegible] iding which costs and which output [illegible] is a co[illegible]le undertaking

The cost-of-service studies mentioned earlier consider only orical costs and not future costs, which are substantially higher A rate design based on a cost-of-service study will apportion responsibility based on the past But, who should pay the cost of new capacity? While the use of marginal cost pricing is an attempt to provide an answer to that question, implementation of such a method of rate design raises a number of complex and, as yet, unresolved issues

This discussion is not meant to impl[illegible] that rates based on marginal and embedded (historic) costs are mutually exclusive Some commissions look at both types of costs in the rate-making process In the electric rate-making process, for example, embedded costs are often used in the determination of customer class revenue allocations, and marginal costs are used to design specific rates or to determine rate relationships (*e g*, [illegible] nd off-peak rates)

[illegible]ors Other than Cost

In the development of utility rates, one must consider not only a utility's revenue requirements, but the relationship between a rate design and the customers to be served We have already considered the cost-of-service concept and its impact on utility rates It is the guiding principle of rate regulation In some instances, however, rates based on some other factor are deemed proper In some instances, for example, social considerations have been noted as justification for setting [illegible] below cost There are several ancillary principles to be considered when establishing rate design View of those considerations are presented below

Value of Service The value of-service principle is explained most frequently as that principle of pricing under which the differences in the prices charged for various products or services are based not just on differences in the costs of production, but also on differences in the urgency of demand Consideration of the value of service is an alternative to strict cost of service rate making It rests upon the differing demands of each group For example, the rate for an industrial electric customer must be lower than the cost of self-generation Rates to other customer classes may be governed by other considerations, including convenience and efficiency Usually, commercial and industrial users of energy are more sensitive to price differentials than residential users They are ordinarily in a better position to appreciate and take advantage of the differentials

The value of service may be considered as one factor among many A high value of service might justify rates above those which would result from strict cost-of-service pricing Similarly, as competitive forces begin to increase the number of alternatives available to utility customers, value-of-service considerations may result in a reduction of prices for certain services

Ease of Understanding Multiple rate forms often lead to unfavorable reactions from many small users, yet such small users are generally the largest group served Thus, the problem of simplifying rate structure becomes a very real challenge to utility companies To improve cust[illegible]ier relations with regard to this issue, utilities periodically mail booklets to consumers that explain their rate structure or engage in similar public relations measures All of these activities are aimed at explaining to customers just how their bills are computed

Ease of Administration and Customer Impact From a purely theoretical aspect, the ideal rate would be one designed to cover (1) the overall expenses of operation and provide a reasonable return on the utility investment, and (2) all the particular expenses of each class of customers in the exact amount or proportion incurred [illegible]tically, however, these objectives are difficult, in fact virtually impossible, to accomplish Furthermore, it is soon found, in working with rate structures, that the greater the effort to find precise allocations of expenses, the more complex the rate forms become And the expense necessary to develop and use very complex forms makes them practically prohibitive for small customer groups On the other hand, such expense and trouble are usually worth the effort for large customers The cost of me[illegible] 'demand' or the use of time meters for large industrial custo[illegible] obviously justified Moreover, the large user of utility service is likely, in his own interest, to have available some person who understands the complexity of the charges

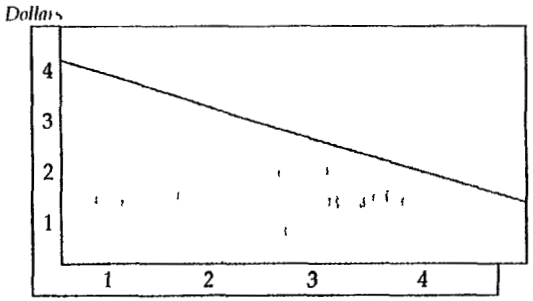
In the case of the small user, the added cost of special equipment, which would have to be recovered from this class of customers, would mean substantially higher bills While some customers might find that their bills would be less under a complex rate, the benefit may be offset by having to pay more, through their rates, to cover the additional cost of rate computation Imagine the reaction of a customer when told that a new type of meter would be installed which would give him the benefit of a sound, scientific rate, but that such installation would make his rate higher because of the additional cost of the meter

Rate Design and Demand for Service

Related to customer acceptance of rate design modifications is consideration of the ***elasticity of demand*** This concept refers to the sensitivity of consumption to a change in price A customer who decreases his demand when the price increases is said to have an ***elastic*** demand The greater a change in consumption for a given change in price, the greater the elasticity

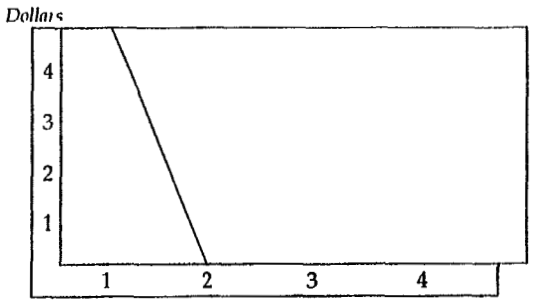
Figure 22–8

ELASTIC DEMAND



NUMBER 1 Quantity of Service Consumed

INELASTIC DEMAND



NUMBER 2 Quantity of Service Consumed

Flasticity is important to rate design and to utilities Innovations in rates will do little good if a customer s demand is highly inelastic On the other hand, customers with highly elastic demand may, for example, be persuaded to shift consumption to off-peak periods (in response to lower off-peak rates) with a beneficial effect for all

Figure 22-8 illustrates the difference in demand elasticity between two typical consumer groups According to the first graph, if a consumer s demand is elastic, reducing the price of a unit of a utility s good from $4 to $2 would result in the consumer increasing consumption from one unit to 4 units While the second graph does not indicate absolute inelasticity, it does indicate behavior typical of the consumer whose demand is said to be "inelastic " When the price is reduced from $4 to $2 the consumer fails to purchase even one additional unit

Variable Loads and Utility Rates

Because the utility must have sufficient capacity to provide service as called for and that the demand for service varies in time, the cost of service is affected in a unique way The company must have sufficient plant capacity and otherwise be ready to serve the largest actual demand which may be placed on the system in any day, month, or year These different types of demand are named accordingly daily peak load, monthly peak load, and annual peak load Of course, the daily peak demand will vary with the day of the week and with weather and seasonal changes Similarly, the monthly and annual peaks will vary Steady growth will be reflected in an ascending series of peaks

The impact of load factor on the cost of providing service is considerable Assume a system with two customers, both using approximately the same amount of energy, but with Customer A having a widely varying load and Customer B consuming relatively stable amounts (See Figure 22-9, page 6 30) The utility would have to have the capacity to meet Customer A's higher peak load, even though that plant may be used for only a short period of time (for example, the hour of peak use on Sunday and Friday) Thus, the cost of serving Customer A would be much higher than that of serving Customer B

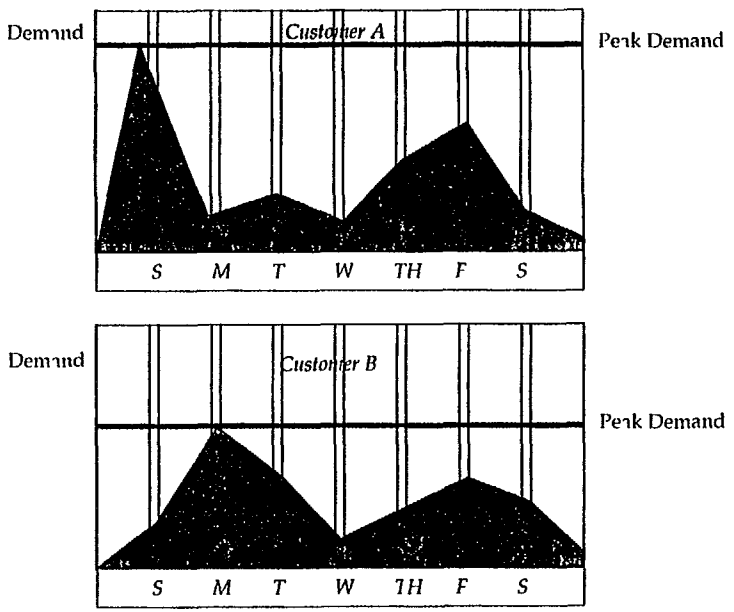
In addition to being ready to serve the various peak demands, all utility companies plan ahead to have an extra margin of reserve capacity available in the event of an emergency The peak load plus the reserve margin determine the amount of total investment the utility company must make to fulfill its service obligations The peak may last only a few minutes each day, or one or two days out of the week, or month Nevertheless, the utility must be prepared to meet it, either through investment in plant, purchase of power elsewhere, or the storage of gas

The extent that a utility's plant or pipeline facilities are utilized is expressed as its ***load factor*** A high load factor means that consumption on a system is relatively stable, *i e* , there are no extreme

peaks and troughs It can be achieved either by having similar customers all with relatively even demands or by having varying uses which tend to offset each other A high load factor is desirable since it reflects efficient use of the utility s generating or gas pipeline capacity

Figure 22–9

VARIABLE SERVICE LOADS



Whether a company s load factor is high or low, the presence of unused capacity during part of the day, month, or year is an incentive to devise special rate schedules to persuade customers to use service during off-peak periods For this type of business, any rate which will yield revenue amounting to more than the company s out of pocket cost of meeting that off peak demand is an advantage to both the utility company and its other customers It helps to spread the revenue requirements among that many more units of service which can be sold during the entire year For comparison, consider auto use The occasional driver is paying more per trip, throughout the year, than one who drives every workday And the one who drives every day in the

year is paying even less per trip, because he spreads the same fixed charges over that many more trips This variation in use patterns is called the ***diversity factor***, which is a term which indicates that there is always a variety in the use of facilities by utility customers

Utility efforts to improve load factors and moderate demand upon their systems are commonly known as load management " Subsequent chapters will comment more specifically on the incentives and programs which have been implemented to help moderate variability of load It is important to note, however, that most, if not all of these programs, depend upon the elasticity of demand and the pricing incentives built into various rate structures

Review Questions

1 What is meant by elasticity of demand? _____

_____

2 What is marginal cost pricing? _____

_____

_____

3 Which of the following customers would be expected to contribute to a high load factor?

a A clothing store in a shopping mall
b An industrial plant which processes widgets
c An elementary school
d A residential homeowner

4 What is meant by the 'functionalization of costs? _____

_____

_____

5 Which of the following are considered fixed costs?

a Energy costs
b Customer costs
c Demand costs
d None of the above

Answers to Questions in Chapter 21

22

1 Beta is a measure of market risk which captures the extent to which a particular company's stock moves with general stock market returns It is used to measure the relative risk of individual stocks

2 The total weighted cost of capital is $64,000 $400,000 x 11% = $44,000, $200,000 x 10% = $20,000

3 The test period is a specified time span chosen to serve as a proxy for setting rates for the future The test period is often the most recent calendar year for which data are available

4 Normalization is the process of making adjustments to make the test period representative of the average operations of the utility Adjustments can be made for many reasons, *e g*, employee wage increases, lower energy sales due to weather conditions, etc

5 Expected future earnings are discounted under the DCI methodology because dollars to be received in the future are not worth as much as dollars received today Thus, future cash flows are discounted back to present value

Chapter 23
Traditional Rate Structures

The earliest rate tariffs charged customers a flat fee which did not vary Practical meters were not yet known so there was no way to measure a customer's actual use Lacking any real relationship to the cost of service, the method was clearly inefficient

The first modification came when utilities charged a rate which varied depending on the number of rooms, outlets, or fixtures This was an early attempt to estimate the burden which a customer placed on a utility It was only a rough approximation, however, and has generally been abandoned—with the notable exception of municipal street lighting, where a count of the number of lights combined with operating data about the light gives a reasonable approximation of the energy consumed

The Evolution of Rate Design

Metered Rates The first significant development in rate design utilized meters to charge customers an amount per unit of service consumed Typically, the charge per unit was the same regardless of the number of units of energy or service consumed The barest consideration of such a uniform charge shows how impractical it would be For example, it should be obvious that it costs an electric utility more per kilowatt hour (kwh) to serve a small or convenience-type customer remotely situated, using only a few units a month, than a large centrally located heavy industrial consumer The former might get a monthly bill for as little as 25 cents, clearly not enough to cover the cost of meter reading, accounting, and billing The latter might get a bill running into thousands of dollars—enough to send the large users in search of alternative supply, including their own generating facilities Clearly, it is important to measure the amount of energy consumed by each customer, but early metered rates were only a step in the right direction for equitable rate design

Step Rates Similarly doomed to short life was the early attempt to provide an incentive for increased use through a series of descending steps or unit costs, in which a *retroactive* reduction for *all* units consumed occurred at various consumption levels An example follows

For the first 50 kwh	6 cents per kwh
For all use up to 150 kwh (including the first 50 kwh)	5 cents per kwh
For all use up to 250 kwh (including the first 150 kwh)	4 cents per kwh
For all use as long as the total is over 250 kwh	3 cents per kwh

The step rate was a little improvement over the uniform flat unit charge, but not much It did provide a promotional incentive but it also introduced a serious flaw of its own The abrupt, retroactive lowering of rates between steps actually encouraged customers to waste consumption when they approached the limits of one step In some cases, customers could actually get a smaller bill by using more service For example, using the above rate schedule, a customer consuming 130 kwh would be billed five cents per unit, or $6 50 By increasing consumption to 160 kwh that customer would pay only four cents per unit, receiving a bill for $6 40

The Block Rate A substantial improvement came with the block rate which eliminated the abrupt step with its retroactive unit rate cut and applied the unit rate reduction in separate, progressive blocks

Declining block rates provide a proportionally lower charge for increased consumption A typical declining block rate structure would be

First 50 kwh	8 cents per kwh
Next 50 kwh	5 cents per kwh
Next 200 kwh	4 cents per kwh
Each additional kwh	2 cents per kwh

A customer consuming 150 kwh would pay eight cents per unit for the first 50 units ($4), five cents per unit for the next 50 units ($2 50), and four cents per unit for the remaining 50 units ($2), receiving a total bill of $8 50 The last (or tail") block is priced lower since there is no demand cost component

Inverted block rates are just the opposite The cost per unit consumed increases directly with consumption The more of the good consumed, the more the charge for each additional unit

The block rate became very popular in the electric utility industry It was easy to understand The declining block rate encouraged consumption, thereby lowering cost per kilowatt-hour to all customers But, it still contained serious flaws and inequities because it failed to recognize the demand factor A few customers using a very large quantity of service for a very short time could require such large plant capacity as to run up the cost of serving other customers who spread their use over longer hours

Two part Rates The demand factor problem was addressed around the turn of the century It was noted at that time that rates should reflect the two basic costs associated with providing utility service—energy costs and demand costs Such a rate design would effectively distinguish between customers based on cost responsibility The concept was applicable to the gas industry as well as the electric industry Available pipeline or transmission capacity was subject to varying levels of demand for service

Minimum Block Rates

Most generally used today is the "block meter rate," which features a substantial initial charge for the first block of usage, with reduced rates in successive blocks, and a monthly minimum charge, which usually equals the initial charge The blocks may be declining, relatively flat, or inverted

In addition to these basic block rates, in many areas utilities have obtained regulatory permission to add special surcharges for cost of fuel adjustment, special environmental costs, and other variables, plus state and local taxes where separately imposed The main advantages of block meter rates are simplicity of application and customer understanding, plus the recovery of most if not all of the expense of serving the customer in addition to the cost of producing and delivering the energy he or she actually consumes

The gas industry uses the same general types of rate forms used in the electric industry The most widely used is the block form with a minimum bill An illustration of this would be

Minimum bill	$2.00 per month
First 5,000 cu ft per month	$2.50 per Mcf
Next 5,000 cu ft per month	$2.40 per Mcf
Next 5,000 cu ft per month	$2.30 per Mcf

Adjusting Rates for Fuel Expenses

Rates for service are set in advance even though all costs are not known The cost of fuel used in generating electricity or the cost of gas delivered by a pipeline to a distributing company is often not certain at the time rates are set Fuel prices can vary significantly over the period of time that the rates are to be in effect How, then, can a utility recover these costs? The solution is through the operation of a ***fuel adjustment clause*** or ***purchased gas adjustment clause*** That tariff provision basically provides for alterations in the charge for each unit of electricity or gas to reflect the varying price of the fuel or commodity

Once approved by a commission, such clauses operate to permit a change in rates without formal regulatory hearings The clauses can be designed to recover other expenses that may not be accurately estimated at the time of the rate proceeding—such as taxes—but, to prevent abuses, they are generally limited to expenses over which the utility has little or no control The clause is not a substitute for a formal rate case It is only a limited interim measure designed to adjust for a single market change—not to substitute for consideration of the myriad issues involved in a full-blown rate proceeding

Fuel clauses are currently utilized in a majority of the states and represent a significant consumer dollar outlay There are almost as many variations as there are states using the clauses Because such clauses are the subject of considerable controversy, a broad description of the pros and cons is in order

Advantages of Fuel Adjustment Clauses First, the clauses protect the utility's rate of return and help it meet its revenue requirements in times of inflation Rates are permitted to keep pace with rapidly escalating fuel prices and the time delay occasioned by processing a rate change proposal is, to some extent, avoided

Secondly, since investors know that the utility will be able to pass through its increased costs, the company becomes a somewhat less risky venture, and its cost of capital is reduced Additionally, the clause provides the proper price signals to consumers, with the result that they pay an appropriate price for their consumption Without the provision, consumers would be paying an out-of-date price for the service they consume

Such clauses also operate to pass fuel savings on to customers immediately Savings from cheaper purchased power accrue to consumers and prevent their being charged at an excessive rate

Disadvantages of Fuel Adjustment Clauses Perhaps the most serious disadvantage is inherent in the automatic nature of the clauses Under a fuel adjustment clause, expenses are paid by customers without commission scrutiny There is reduced incentive for a utility to obtain the lowest price for purchased fuel when it knows that the entire cost can be passed on to ratepayers

Other criticisms are variations on this same theme Critics maintain that fuel adjustment clauses

1. abrogate consumers rights to examine and challenge the utility s rates
2. provide an incentive to substitute fuel costs for factors which are not covered by the automatic mechanism
3. encourage managerial inefficiency, since at least some increased costs will not be penalized through a reduction in earnings

Finally, a major problem with fuel adjustment clauses relates directly to one of the criteria for a good rate structure Consumers often have difficulty understanding the more complicated rate structure Why they should pay another charge for fuel when their rates are already so high is a common complaint

There are no easy answers to the questions presented by application of such fuel adjustment charges Each commission must weigh the benefits and detriments considered here and each should apply that method which best serves the interests of both the utility company and its consumers

Public Utility Regulatory Policies Act

A reexamination of this nation s energy policy during the 1970s included scrutiny of electric and gas utilities, as both consume and supply a large portion of energy in the United States The culmination of congressional deliberation was the National Energy Act of 1978, a collection of five statutes which sought to remedy problems with supply and distribution of energy The part of the act most directly affecting utility rate design is called the Public Utility Regulatory Policies Act (PURPA)

PURPA created a number of new approaches to utility rate making These have resulted in differential charging for specific objectives not necessarily connected with the traditional cost of-service basis examined earlier Provision was also made in the legislation for the consideration of prohibitions against master metering, rate discrimination of all types, abrupt service termina-

tion, and political and promotional advertising, and activity at the ratepayers' expense The reasons for these departures are clear enough once they are understood

The act required that regulatory policies be established for new programs directly affecting electric and gas utilities to promote four objectives (1) conservation, (2) efficiency, (3) equitable retail rates for electricity, and (4) equitable rates for natural gas customers It also addressed issues of distribution, reliability, and rate procedures for wholesale electricity

There is a basic distinction between what the federal government may regulate and what is within the jurisdiction of the state commissions How then can the federal government decide what rates a utility should charge its local customers? In 1982, the United States Supreme Court noted that the act does not purport to confer upon federal authorities the right or the power of final decision making on any utility rate-making issues which traditionally have been regarded and treated as falling within the jurisdiction of the states Rather, the act set up objectives which constitute important parts of the national energy policy It required the states to consider certain rate-making standards and techniques and to determine whether, and to what extent, they are conducive to the attainment of the stated ultimate objectives of energy policy On the basis of their own determinations, the states then may utilize any or all of them in setting utility rates—wholly, in varying degrees, or not at all The Supreme Court ruled that Congress in passing the law was acting within its authority under the Constitution to regulate interstate commerce and, in so doing, did not infringe upon rights reserved to the states by the Tenth Amendment

PURPA's Differential Rate Standards

The six electric rate-making standards which the state commissions were required to consider under PURPA were cost of-service pricing, declining block rates, time-of day rates, seasonal rates, interruptible rates, and load management techniques Each standard involves some degree of differential pricing

Cost-of-service Pricing PURPA required each state commission to consider cost of service for electric utilities as reflected in their rates Utilities in most states are now reporting some cost-of-service figures by customer classes as is required by law Cost-of-service pricing requires cost justification based upon the volume of use by different classes of customers

Prohibition on Declining Block Rates unless Cost Justified This standard responded to criticism that the final consumption block rate (or tail rate, as it is called) may be too greatly reduced, compared with other blocks The inference was that this low-cost block unduly favored large use consumers, as compared with smaller use consumers

Time of day Rates These rates are a shortcut to placing the cost responsibility directly on those ratepayers who contribute to peak-load demands on the utility plant By placing a higher rate on peak-hour use, the customer is theoretically given a price incentive for shifting his use to times when it is cheaper for the utility to generate electricity There are, however, practical questions whether customers might change their loads to create new peaks as a consequence This would leave the utilities "chasing the peak around the clock

Time-of-day rates must be specially metered, raising some question of expense and administration Under PURPA, this rate standard would be considered for implementation only if proven to be cost effective, *i e*, if the benefits exceed the installation costs of meters

Seasonal Rates Similar in principle to time-of day rates, seasonal rates provide off-peak advantages on a seasonal rather than daily basis, if a utility s costs vary on a seasonal basis Rates for air conditioning in the summer and space heating in the winter would fall into this category

Interruptible Rates Interruptible rate schedules for natural gas customers have been in use for years, they usually affect large volume industrial or commercial steam generators The fifth PURPA standard required electric utilities to offer interruptible rates to commercial and industrial customers, based on the cost of serving those within the class Many residential customers who limit electricity consumption to specific end uses, such as space heating or water heating, are also covered by interruptible rate schedules Under interruptible rate schedules service may be curtailed at any time

Load Management Techniques Although PURPA identified 'load management techniques as one of the six standards, which state utility regulators were directed to consider, three of the rate types discussed above as standards can be utilized as load management techniques—whose cost effectiveness will vary with circumstances

This chapter has reviewed some of the early forms of rate design and described the block rate structure—a form widely used for many years We have also briefly examined some of the provis-

ions of PURPA which introduced some changes in utility rate design, particularly for electric utilities The nature of the electric and gas utility industries is changing These changes are accompanied and caused by certain changes in utility rate design which will be examined in the next few chapters

Review Questions

1 Identify one advantage and one disadvantage of fuel adjustment clauses _____

_____

2 What are declining block rates? _____

_____

3 Define the term load factor _____

_____

4 What were the four major objectives of PURPA rate standards? _____

_____

5 What are seasonal rates? _____

_____

Answers to Questions in Chapter 22

1 Elasticity of demand refers to the sensitivity of consumption to a change in price Customers who decrease their demand for a product or service when prices increase, exhibit elasticity of demand The greater the change in consumption, the greater the elasticity

2 Marginal cost pricing is based on the cost of service at the most recent or next immediately required plant The rate charged equals the cost of producing one more unit or the savings from producing one less unit of service

3 The correct answer is "b

4 Functionalization refers to the assignment of costs into the functional categories of production, transmission, and distribution

5 The correct answer is "b

Chapter 24
Emerging New Rate Structures

During the 1980s, changing economic conditions precipitated and were accompanied by changes in utility rate design Some of those changes included the "unbundling" of rates, others focused on regulatory treatment of rate base, and some focused on market demand for services This chapter will highlight some of the innovations in rate making that have been adopted by various commissions during the past several years While the discussion is not inclusive of all the issues which have been considered by regulators, it does report on those new rate designs on which there has been significant regulatory action

Utility service has historically been sold and priced as a complete package or ***bundled*** service Cost of service studies however, have always recognized that the final delivered service is actually made up of a number of separate and discrete functions For both electric and gas utilities, there is an acquisition of supply and a transportation function Utilities with their obligation to provide service to all customers at all times, must also provide for internal reserves, either through excess capacity, purchase agreements, or storage, for failed supply In addition, they must maintain a certain degree of redundancy in their systems for transportation and transmission outages

Can these and other separable functions be priced individually and even sold competitively? The practice of separating these functions for individual pricing and possible competitive offerings has been referred to as the ***unbundling*** of utility rates and services

Unbundling Natural Gas Rates

The primary event in the unbundling of natural gas rates has been FERC Orders No 436 and 500 Order 436, issued October 9, 1985, established an "open access" transportation program which made it more possible for parties other than utilities—notably end users—to transport their gas over interstate natural gas pipelines and divided the pipelines' gas marketing and transportation functions While the details of the combined orders are complicated and require an understanding of the gas supply situation prior to the orders (see the handbook on Delivery of Service), the effect was to unbundle interstate gas pipeline service into a number of components, the primary two being gas transmission and gas commodity sales

Upon further analysis, it becomes clear that interstate gas transmission companies rates include, within the bundled package, more than just two elements Gas service can be further divided into at least four discernible areas

- Gas commodity sales
- Gas commodity purchase rights at certain times
- Transportation capacity at certain times (with implied ability of storage service)
- Gas transportation service

The gas industry and its customers quickly determined that each of the four components was valuable and could be valued differently by different customers and that these services could be sold separately The reality of natural gas industry markets was that large customers could and would acquire their own gas supply and did not need, nor want, all the bundled service offered under traditional interstate gas rate tariffs

The same gas which interstate gas transmission companies transported for end-use or ***burner tip*** customers under unbundled rates needed to be delivered to those customers through the facilities of local gas distribution companies Some state commissions accomplished this by providing for special tariffs which attempted to design a rate combining the local distribution costs with the gas commodity costs allowed by the FERC under special marketing programs Others realized separate transportation tariffs were necessary to cover the variety of conditions and service now offered in the competitive market The impact of the FERC orders was to put pressure on the local gas distribution utilities and state regulatory commissions to allow the same choice in unbundled services as was available for interstate gas transmission

Local gas distribution companies found themselves needing to develop rates for all the newly unbundled services demanded by increasingly aggressive customers and, in some cases, public service commissions With transportation uncoupled from gas marketing, new companies entered the local service territory offering gas supply in competition with the gas acquired by the local distribution on behalf of the customers An element of uncertainty and risk was added to the local distribution company operations, as the utility was no longer able to assume that it needed to or should acquire gas on behalf of all customers historically served The distribution companies and state regulators were faced with questions concerning the obligations of gas supply service now incurred by local gas utilities in the new competitive and unbundled environment

Traditional gas service was found to include provisions for a number of options allowing for differences in customers' tolerance for service reliability, cost, and timing New tariffs were developed to accommodate the following unbundled service requirements

- Firm gas service (traditional bundled service)
- Interruptible gas service
- Transportation service (Customer acquires supply or Utility acts as agent to acquire supply)
- Long-term "back-up" to customer acquired supply
- Supplemental gas supply (excess acquisition)
- Gas acquisition services
- Storage for customer acquired gas

While several of these types of tariffs rely on traditional principles of rate design (notably firm gas service and interruptible service), there has been considerable debate over the appropriate costs to be included in transportation charges The focus of this debate has been the assignment of the utility's fixed costs to the transportation customers When the local gas utility transports gas owned by other parties, should the remaining customers taking bundled service be required to bear all fixed costs?

Transportation Rate Design

A number of methods have been adopted in the development of gas transportation rates by distribution companies One principle endorsed is that the local utility and its earnings should be neutral as to whether a customer chooses to buy gas from the utility's system supply or from a third party That is, there should be no adverse effect on the utility when it agrees to provide transportation service instead of bundled service The decision as to what method of allocation of fixed costs to use has a significant impact on the levels of rates to the customers remaining with the system supply Factors such as the ability of certain customers to not buy gas at all and leave the system (and fixed costs behind) further complicates the allocation choices

Among the most commonly adopted methods for allocating fixed costs to transportation customers are

Minimum cost of service method Only direct transportation costs are charged No fixed costs are recovered through these rates

Simple margin method Some fixed costs are recovered by taking the regular bundled gas service rate and subtracting the utility s embedded gas cost In other words, the simple margin method bases the transportation rate on the comparable sales rate minus the *average* cost of gas The average cost of gas includes the commodity cost of gas, pipeline transportation and demand costs, storage costs and peaking costs

Gross margin method All fixed costs are allocated as in traditional cost of service studies Variable gas costs are the only costs excluded from the cost of providing service Thus, the gross margin method is based on the comparable sales rate minus the *commodity* cost of gas

Flexible rates These include a range of rates based on market conditions in order to maintain customers on the system They are also referred to as ***value of service*** transportation rates

The California Public Utilities Commission in 1985 issued a widely discussed order requiring gas distribution companies to provide long term transportation services based on margin contribution principles The ensuing rate included three parts a fixed monthly charge for connection and access to the local distribution system, a demand charge for usage and storage, and a flexible volumetric charge Subsequently, this commission established a new definition for "core and non-core customers, and provided for different levels of service choices from among the unbundled gas services

The significance of this order by the California commission is that it also included a clear statement as to levels of service obligation of the local gas utilities to both identifiable market groups ***Core customers*** (those who lack the opportunity to secure alternate supplies of gas) continue to receive bundled services with the utility bearing the attendant obligation to provide reliable service on demand Non core customers trade off various degrees of assurance of service depending upon the service option they choose and the specific provisions of their service contract with the utility

The FERC orders on gas transportation had the effect of forcing pipelines to offer unbundled services to a wider range of customers The effect of these orders was felt downstream by local distribution companies and amplified by customer requirements and state regulatory policy Thus, both the interstate pipelines and local distribution segments of the gas industry have moved in the direction of being in the transportation business as well as the gas merchant business

Emerging New Rate Structures

According to the American Gas Association, transportation rates have been implemented in all natural gas market segments According to a survey conducted by AGA in 1990, transportation strategies are in place at most local distribution companies Ninety three companies (92 percent of survey respondents) in 138 service areas in 46 states and the District of Columbia now offer a transportation rate as a method of retaining and expanding gas volumes Natural gas moved under these tariffs accounted for more than a quarter of local distribution company gas requirements and 7 5 percent of net company revenues in 1990 The average distribution company with transportation service provided such service to 287 customers

Transportation rate designs differ between firm and interruptible rates and services Firm transportation rates are frequently based on gross or simple margin, while interruptible rates are often designed on a negotiated or value-of-service basis In 20 percent of the respondents service areas, transportation rates are restricted to dual-fuel customers Flexible pricing provisions are available on 40 percent of firm transportation rates and on 66 percent of interruptible rates In past surveys conducted by AGA, the gross margin approach to transportation rates had been the most frequently used rate design Since 1986, however, the percentage of companies using this method has declined Negotiated transportation rate design has increased while margin based rate design has declined Of course, many companies have more than one transportation rate and the design often differs from rate to rate

AGA reports that since 1985, nearly five times as many companies in seven times as many service areas now offer a transportation rate The greatest growth in the number of transportation rates has occurred in the commercial market The percentage of respondents with interruptible commercial transportation rates has more than quadrupled and companies with firm commercial transportation rates have increased five-fold

Unbundling Electric Utility Services

The Federal Energy Regulatory Commission, which addressed the problems of gas transportation, faces similar questions with respect to the separation of electric generation and

transmission services in the interstate market The FERC has had the opportunity to set transmission rates in the past for jurisdictional electric utilities voluntarily involved in wholesale electric transactions (wheeling") The enactment of PURPA in 1978 increased the number of nonutility generating facilities—cogenerators and independent power producers—and established procedures for the sale of their energy into the electric utilities' mix of owned generation and purchased power

It was only a matter of time before the new independent power producers and qualifying facilities pressed to have the ability to purchase transportation type' transmission services from electric utilities owning the nation s electric transmission grid Without the availability of such transmission services, nonutility generators are locked into markets where the only potential buyers of their power are the local utilities with which they are directly interconnected

The subject of electric transmission access is one of considerable debate at both the state and federal levels One of the key issues in that debate is that of pricing the service While wheeling rate structures have existed in the United States for some time, the development of open access to electric transmission systems foreshadows a potentially significant increase in the number and types of transmission service agreements

In agreeing to provide long term transmission service, a utility is faced with significant risks—as well as opportunities The risks include proper forecasting of load growth and forecasting the location of future generating units—not only on its own system, but on neighboring systems There is also the question of having the ability to construct new transmission facilities and the risk that such facilities will not be adequately supported over the life of a fixed-price transmission contract Despite demands for transmission service that may fluctuate with market conditions, utilities must plan and build with reliability as a prime consideration

The costs of providing transmission service vary from one utility to another Thus, some industry observers believe that the parties involved should have flexibility in designing the rates, terms, and conditions that are appropriate for each transmission service agreement The use of an embedded cost methodology in establishing firm transmission service, for example may understate the costs of providing the service and does not reflect the loss of savings stemming from the availability of the transmission system for alternative uses, such as economy power transactions Because the construction costs of new transmission facilities is likely to be substantially greater than the historic embedded cost

of the existing system, embedded cost pricing may discourage utilities from installing new lines to provide transmission service

A considerable amount of experimentation and change is already underway in the area of transmission service across the country today This trend has been motivated by the desire of utilities to enhance their future electric supply options and market opportunities in the generator sector

The issue of unbundling electric service is not as well developed at the local electric utility level as it is in the gas industry But the issues are not far behind if FERC actions lead to the concept of mandatory wheeling of a third party s electric energy over utility-owned power lines Questions of cost allocation, reliability of service, obligations of service, and requirements for standby and back-up power will all confront and sometimes confuse utilities, regulators, and customers alike

Rate Phase-ins by Electric Utilities

In traditional rate-making practice, an electric utility is permitted to include a new plant in rate base when the plant is completed and placed in service, so that the utility may earn a return on its useful investment Alternative strategies have been investigated, however, as state commissions attempt to incorporate new plant into rate base without causing precipitous increases in rates ("rate shock") and without jeopardizing the interests of utility investors

Although now several years old, a 1985 decision by the Missouri Public Service Commission serves as a good example of a rate base ***phase-in plan*** The commission authorized an eight-year phase-in plan for the Union Electric Company's Callaway nuclear plant The phase-in was to be accomplished by deferring the equity return on Callaway rate base

The eight-year plan would involve six years of rate increases, followed by two years of recovery of deferred equity The rate increase in the first year was 14 percent, with a 10 percent increase in the second year, and a 7 29 percent increase in the next four years The commission rejected a seven-year plan, finding that because of the magnitude of the Callaway investment, a shorter rate base transition period would require a 25 percent rate increase in the first year, an increase deemed too high for ratepayers to bear

The commission s rationale was that a definite phase in period gives a utility incentive to postpone any other rate filings for several years and eliminates uncertainty within the investment

community as to any risk about the ultimate rate base allowance for the plant

The most frequently cited rationale for implementing a phase-in plan are (1) the need to avoid rate shock and (2) the importance of rate continuity Phase-in plans have been accepted in a number of states and since 1985, there have been more than 25 major decisions which have addressed electric rate base phase-in plans

Recent examples of such plans includes the case of Gulf States Utilities, a utility attempting to resolve the disallowance of $1 4 billion of its investment in the River Bend generating plant After a Texas commission ruling in 1986 excluding that investment from rate base, the company in 1989 proposed a plan to phase those costs into rate base With the plant excluded from rate base, Gulf States earnings have been negligible and return on equity has averaged only 0 2 percent, the company has not paid a dividend on common or preferred stock since 1986 and has been unable to sell first mortgage bonds By late 1991, the case had yet to be resolved

The River Bend case represents one of several instances where regulatory commissions have been reluctant to accept—or have rejected—proposed phase in plans In some cases, the commission has ruled that the proposed revenue requirement did not constitute rate shock and a phase in was therefore unnecessary In a 1984 case, the Iowa commission rejected a five year phase in plan explaining that the plan would merely delay the addition of capital costs to rate base, but could not protect ratepayers from rate shock in the long term, without any assurance that the capacity and load would be any better matched in the future

Phase in plans may also serve as a means of incorporating into rate base new plant that is placed in service but is determined by the commission to represent excess generating capacity In 1987, the Indiana Utility Regulatory Commission ordered a rate base phase in for the R M Schahfer unit 18 after it determined that the plant was not "reasonably necessary for the provision of adequate and reliable service The phase-in period matched the rate at which the utility would need additional reserve capacity in the future

A frequent criticism of rate base phase-in plans is that such plans create a greater financial risk for the utility because of the possibility that deferred assets may never be collected The company's credit rating and cost of capital may also be affected Proponents counter that traditional, immediate inclusion of new plant costs in rates may not always mean the least risk for utility management Given the difficulty of forecasting a sales volume sufficient to generate revenue requirements when a large increase is implemented, investors may have a better opportunity to recover all costs associated with new plant if a deferral plan results in a high probability of actually collecting approved revenues And, in the case of the River Bend plant, the utility would prefer deferred revenues to a total disallowance from rate base

Another criticism of phase in plans is that they improperly shift the costs of new plant to future ratepayers, while current ratepayers enjoy the benefits without paying the actual cost of service There remain disagreements among commissions regarding the treatment of plant deemed not currently used and useful And there are varying opinions about the merits of phase-in plans Such plans are generally proposed only when very large plant investments are being considered for rate base treatment Proposals for phase-in are evaluated on a case-by-case basis, keeping in mind the interests of ratepayers and utility investors

Excess Capacity Determination

In 1980, the Missouri Public Service Commission stunned the utility industry with the news that it would not permit Kansas City Power and Light Company to start earning a return on its investment in a newly completed electric generating plant said by the commission to represent "excess capacity Today, as mentioned above, rate-making adjustments for excess capacity have become commonplace, tending to follow one of three methods (1) rate base exclusion, (2) revenue adjustments, or (3) disallowance of return on common equity

State commissions do not agree on a single standard for determining the existence of excess capacity, instead suggesting a multitude of theories Among the methods employed are a prudent investment test, a used and useful test, a reserve margin calculation and an economic analysis of benefit to consumers The Indiana commission has identified eight factors as relevant to the determination of the existence of excess electric generating capacity

- ✓ The prudence of management decisions in constructing the unit
- ✓ The reasonableness of demand forecasts at the time construction was begun
- ✓ Whether changed circumstances have occurred and if the utility reevaluated its construction program in light of those changes

- ✓ The lead time required to construct the facility
- ✓ Whether the facility is necessary to provide adequate and reliable service
- ✓ Unique circumstances which might affect reserve margin
- ✓ The financial effects of a rate base exclusion
- ✓ The effects of changes in demand forecasts on reserve capacity

These criteria reflect consideration of prudency, the used and useful rule, and calculation of reserve margins The economic analysis, or cost-benefits test, is often utilized to determine whether the exclusion in rate base produces a net benefit to ratepayers and ds to enjoy a greater application in retaining alleged capacity in the base, rather than excluding it from cost recovery

Where commissions have determined the existence of excess capacity and acted to adjust rates, they have generally done so either by excluding a portion of the cost of the plant from rate base, adjusted revenue requirements to reflect a hypothetical sale of excess capacity or disallowed a return on common equity of that portion of the rate base represented by excess capacity This type of rate of return adjustment is less severe than a rate base exclusion and compels ratepayers to share the cost of that excess capacity with utility stockholders There are many examples of the use of all three types of rate adjustments by state regulators

Rate Design for Standby Electric and Gas Service

With the advent and increasing popularity of "self-help electric generation and natural gas transportation opportunities, electric and gas end users have increased their demand for supplemental, backup, or ***standby*** utility services In both the electric and gas utility industries, questions have arisen on how to classify and treat such standby service and how to structure rates for those services

Standby service may be known alternately as backup, maintenance, auxiliary, or supplemental service The keystone of standby service is the "on call" nature of a utility to provide additional power or supplies without prior notice of when that power might be needed and a utility's facilities may be called upon

A federal appeals court has held that standby service is an appropriate service classification and that standby or availability charges qualify as "rates" instead of monetary penalties for failure to maintain firm requirements demand The court explained that a utility incurs standing ready to serve customers at all times, and that standby charges can be structured almost limitlessly, including per-unit consumption charges and ready-to-serve charges

Using a similar line of reasoning, the Michigan Public Service Commission has stated that there are valid costs associated with the guarantee of sufficient available capacity to meet the demand of a particular customer and that all customers should be required to share in such costs, regardless of whether a standby customer actually takes service The commission said that it is the cost of potential for demand, rather than actual demand requirements, that comprise standby charges

The Utah Public Service Commission has held that standby charges enjoy a cost justification as a substitute for administrative disconnection and reconnection charges Particularly in those areas with a number of seasonal customers, the commission discovered that standby fees help to discourage seasonal disconnections, to ease small utilities maintenance requirements, and to provide a steadier flow of revenues

Prior to establishing such standby rates, commissions had to carefully define what constituted backup power, supplemental power, and standby gas service The Maine Public Utilities Commission, for example, separated standby electric service into several categories, defining backup power with respect to cogeneration and small power production facilities (QFs) as energy or capacity supplied by an electric utility to replace energy normally produced and utilized by the QF's own generation equipment The commission noted that ***backup power*** is usually needed only during an unscheduled outage, distinguishing it from ***maintenance power***, which, although a form of replacement energy, is provided only during scheduled outages ***Supplemental power*** was distinguished even further as being energy or capacity regularly supplied to a QF in addition to that power which the QF itself generates

With respect to gas distribution, the New York Public Service Commission added another definitional layer to the term standby service by recognizing a "self-help category of service under which industrial and commercial customers who obtain most of their gas supplies directly from producers occasionally need additional small amounts of gas to meet their requirements

Remember these definitions vary across jurisdictions and reflect different standards imposed by each commission There is no one definition which can be applied, and tariff decisions are generally made on case specific bases In examining the cost components of standby service rates, commissions will review various demand, energy, and customer costs Production and transmission costs may be recovered through reservation or daily demand charges Embedded customer costs, such as fuel costs, tax expenses, and administrative costs must also be allocated

Economic Development Rates

Prompted by changing market conditions, electric and natural gas utilities have begun targeting certain industrial customers through the used of discounted ***economic development*** or ***incentive*** rates Both economic development and incentive rates have been proposed and the terms used interchangeably, although they differ in subtle ways Economic development rates are offered with the express purpose of attracting new business and thus creating new jobs and stimulating local investments Incentive rates are essentially promotional and attempt to increase sales to high elasticity customers regardless of the purpose of the increased sales

As with most questions where a balance of interests must occur, state commissions have ruled on both sides of the issue Several state commissions have authorized economic development rates, incentive rates, or similar discount mechanisms The purposes vary However, all appear to agree that industrial development rates may be appropriate if they will aid the economy and thus benefit all consumers in the long term

According to a survey conducted by the American Gas Association in 1991, gas distribution companies operating in 31 service areas in 20 states use economic development rates to encourage commercial and industrial customers to increase their gas usage The bulk of the companies offering such rates are located in the Mid-Atlantic region of the U S For the most part, economic development rates offered by gas companies are restricted to new customers or those who increase their usage by some specified percentage The minimum amount of gas consumption necessary to qualify for these rates ranges from 0 Mcf to 108,000 Mcf per year The length of time a customer may take the rate ranges from one to ten years, with most offering a term of either three or five years Many of these economic development rates are negotiated between the utility and the customer Approximately 40 percent of the gas utilities responding to the AGA survey reported the use of incentive rates to sell natural gas for air conditioning The bulk of those companies are located in the South and the Southwest U S

Several specific examples illustrate the types of rates which have been implemented The Alabama Public Service Commission approved an industrial development rate for the Alabama Gas Corporation The tariff schedule was intended to encourage new or expanding business to locate in the company's service territory Under the terms of the plan, the gas company could offer a discount of up to 10 percent for up to five years to prospective gas customers with gas requirements of 300 Mcf per day or greater In Michigan, Consumers Power Company sought a special incentive electric metal melting rate for industrial furnace operators to help offset poor economic conditions in Michigan The special rate would use the maximum demand as the basis for determination of billing demand rather than on-peak demand, as used in other industrial rates The commission approved the rate, explaining that it would not increase the cost of service to any other rate class and would not be unduly discriminatory, because it would be available to any qualifying customer

Anti-Bypass Discounts

Since the enactment of PURPA in 1978, large-volume customers of electric utilities have greater incentive to develop their own generation facilities to meet their electric requirements To preserve load for contribution to fixed costs, electric utilities have sought to offer reduced rates in exchange for a commitment to continue taking service Such 'anti-bypass' offers are typically limited to customers whose consumption greatly affects overall system costs and rates

In a 1990 order approving a special anti-bypass contract for electric service, the California Public Service Commission reviewed guidelines to be incorporated into contracts designed to prevent the loss of large customers In accordance with the guidelines, contracts to discourage self-generation should (1) set a floor price to protect other ratepayers from making an unfair contribution to fixed costs, (2) limit eligibility to customers having base demands of at least 1,000 kw, (3) limit contract duration to a maximum term of five years, and (4) provide time-differentiated rates Electric utilities were authorized to incorporate both rate discounts and conservation incentive options into price terms in the contracts

As with electric utilities, bypass is potentially a problem for local gas distribution utilities which are subject to loss of load when large customers arrange direct access to a pipeline supplier In addition to diminished contribution to fixed costs, bypass can

adversely affect remaining customers by reducing the economies of scale achieved by local gas utilities

In a 1989 rate order, the Washington Utilities and Transportation Commission held that reasonable economic and regulatory measures to discourage bypass would be approved, but not at the sacrifice of continued cost-based service to customers lacking competitive alternatives All customers were obligated to contribute to common system costs, the commission held, and customers with competitive alternatives to service should not be released from that obligation in exchange for a short-term obligation to remain on the system Disproportionate rate reductions to industrial customers for insignificant contributions to fixed cots were inequitable, the commission stated, and would not be approved for rate-making purposes Therefore, in that order the commission denied approval of special anti-bypass rate contracts with a high-volume industrial customers

These two cases illustrate the quandary of utilities and regulators when faced with the threat of bypass How does the utility retain important load without penalizing those customers who have no other alternatives? The question usually boils down to several key issues

- What is the likelihood that a large-volume customer will bypass the utility system?
- What is the customer s load share? Will loss of the customer materially affect utility revenues?
- Does the utility receive adequate contribution to fixed costs? Will a rate discount (cutting revenues) harm ratepayers more or less severely than if the customer leaves the system?

The public utility commission must consider the likely fiscal impact on the utility—both with and without implementation of the anti-bypass rate—relative to any rate discrimination against remaining customers Since 1989 commissions in 15 states have issued more than 25 rate orders regarding anti-bypass discounts The most valid conclusions that can be drawn from these cases at this time is that there are no broad rules that can be universally applied Each case must be decided on its own merits, keeping in mind the interests of the utility and all of its customers

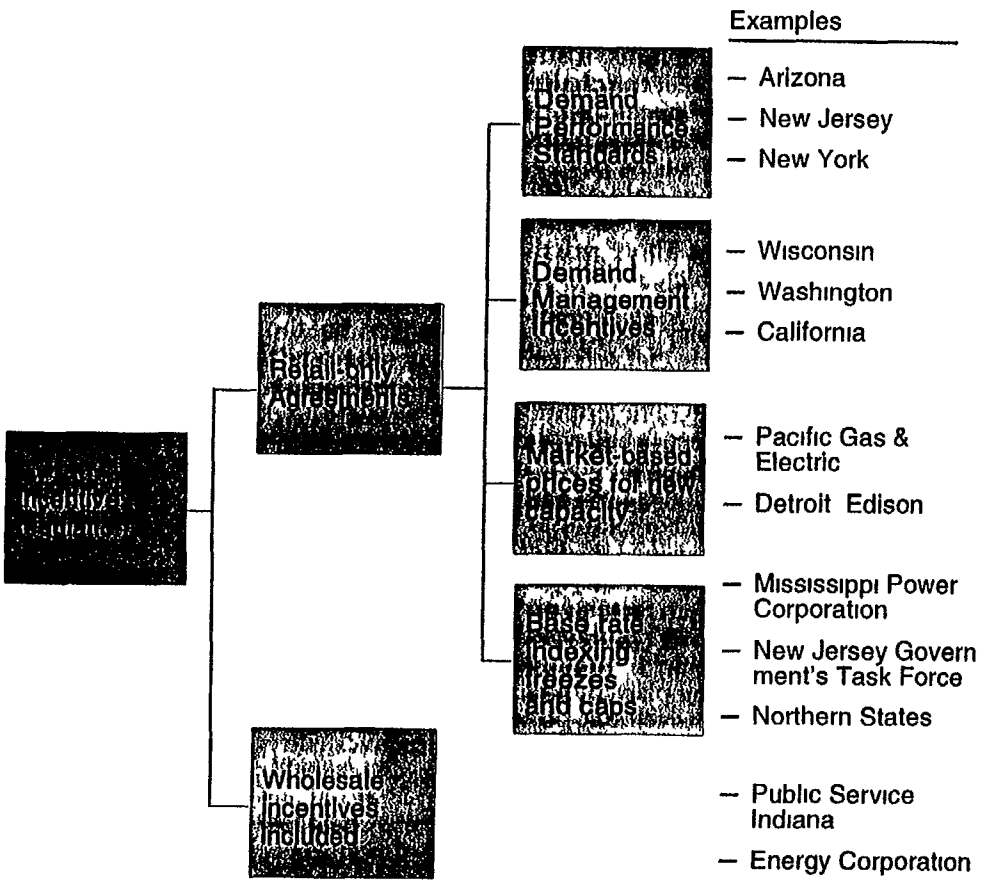
Price Cap Regulation

In the 1990s, the marketing challenge for utilities will be more complex Instead of simply holding onto all customers,

utilities will have to focus on shaping their load curves and targeting specific customers with high-value service Getting regulatory approval for sophisticated marketing approaches will be difficult under traditional regulation because these efforts will require pricing flexibility There is however, no widely acceptable alternative to traditional rate base/rate of return regulation As a result, the electric and gas utility industries are keenly interested in the experiment currently unfolding in the telephone industry the price cap approach being followed by the Federal Communications Commission in regulating AT&T, and by many states in regulating local telephone companies

Figure 24–1

ELECTRIC UTILITY INCENTIVE REGULATION ALTERNATIVES



In 1987, the New York Public Service Commission approved the first ***price cap*** program in the U S Price cap is defined as any broad program to limit price increases, as opposed to limiting returns on investment Today, many states have price cap programs in place, and most of the rest are actively considering some kind of reform The telephone experience is relevant for several reasons like other utilities, the telephone industry is facing competition from bypass by its largest customers, phone companies also lack the pricing flexibility to respond under traditional regulation They also have little incentive to cut costs or invest heavily in marketing under traditional regulation, because they—like other utilities—have found that shareholders do not benefit beyond the next rate case

One of the most difficult challenges for the telephone industry—as with other utilities—is investment in new capacity Expensive investment is difficult to justify, partly because of the risk of incomplete cost recovery and the difficult of realizing higher returns, if successful The consensus is that price caps can help meet the challenges of these more competitive times The goal of price cap regulation is to instill sufficient profit motive to encourage efficiency and innovation while protecting ratepayers Under such a policy, a ceiling is placed on rates, rather than on earnings (rate of return) There may be price movement for different kinds of service as long as the price remains below the ceiling Those price ceilings may be adjusted for any major observable cost changes or expected improvements in utility company productivity Utilities are limited by a maximum amount they may charge for their services, but the more efficiently they provide that service, the greater the potential for their profit

Experimentation with this rate form is already underway in the electric utility industry Much of this has focused on performance incentives, rather than full-fledged price caps But attention is now turning to more comprehensive price cap agreements For example, Mississippi Power Corporation has a performance evaluation plan that provides for high returns according to utility performance on seven performance factors Northern States Power has proposed a broad outline of a price cap to its regulators And PSI Energy (formerly Public Service Company of Indiana) has proposed a rate moratorium and profit-sharing plan in exchange for retaining some profit from more aggressive bulk power marketing Figure 24-1 indicates some of the incentive regulation alternatives currently being implemented in the electric utility industry

To assess the trade offs involved in adopting price caps, utilities should first quantify the opportunities to create value Marketing effectiveness can certainly be improved with price flexibility, and all utilities have opportunities to cut costs But unless these opportunities are subjected to rigorous analysis, a price cap program may be based on overly optimistic estimates Management should be able to quantify these expectations That is, if a utility expects a series of unfavorable orders under traditional regulation, the company should be able to quantify the fiscal impact of such orders and the projected benefits of price caps

Utilities that decide to pursue price caps need to work closely with the commission and carefully guide negotiations so that both the scope and terms of the agreement lead to benefits on both sides The agreement will specify which customers will receive price caps and which cost elements will be included under the cap Cost elements that are beyond management control (e g , acid rain clean-up requirements and oil/gas prices) may be excluded or indexed The terms of the agreement will include a price promise and a level of service promise The price promise will probably include an initial rate concession, an inflation factor, and some productivity offset To satisfy regulators, the price promise will have to be below what regulators expect to allow under traditional regulation The service promise is designed to assure that service wont deteriorate under a price cap, which could happen if cost-reduction efforts are pursued too aggressively

The debate about whether price caps make sense for utilities will go on The answer for electric and gas companies is likely to be the same as the answer for telephone companies under the right conditions price caps make sense In this chapter we have touched briefly on some of the more prominent new rate structures being implemented and proposed for the electric and gas utility industries It is by no means a comprehensive picture of the activity taking place in this arena throughout the U S It should, however, serve to indicate a growing movement toward flexible pricing and competitive marketing efforts while attempting to safeguard the interests of "captive" utility customers

Review Questions

1 Explain what is meant by the "unbundling of utility services

_____

_____

2 Among the methods for allocating fixed costs to gas transportation customers, which allocates all fixed costs in those rates?

a Gross margin method
b Simple margin method
c Minimum cost-of-service method
d Flexible rates

3 What is the purpose of economic development rates?

_____

_____

4 Why are standby charges for electric and gas service considered to be rates instead of penalty charges? _____

_____

5 How does price cap regulation differ from traditional rate of return regulation? _____

_____

Answers to Questions in Chapter 23

1 Advantages The utility s rate of return and ability to keep pace with fuel expenses are protected in times of inflation The company's cost of capital is reduced as investors perceive less risk Customers receive appropriate price signals

Disadvantages Expenses are paid by customers without commission scrutiny Incentives for efficient management and fuel purchases by the utility are reduced Fuel costs may be substituted for factors not covered by the clause

2 Declining block rates provide a proportionally lower charge for increased consumption

3 Load factor is a measure of the degree of utilization of a utility system—either generating plants or gas pipeline In the case of electric generating capacity, load factor is the ratio of average load to peak load on the system

4 The objectives of PURPA rate standards are to promote conservation, efficiency, equitable rates for electricity, and equitable rates for natural gas customers

5 Seasonal rates provide off-peak price advantages on a seasonal, rather than daily basis Rates for air conditioning in the summer and space heating in the winter fall into this category

Chapter 25
Rate Proceedings

We have considered the major principles of utility rate design and examined recent trends in rate making This chapter will consider the context in which these ideas are considered—the rate case

Simply stated, a rate case is the end product of dissatisfaction with a preexisting level of utility rates It is usually preceded by an investigation into the justification of utility rates regardless of whether rates are sought to be increased or decreased The rate case is not necessarily a formal proceeding Rates can be increased or reduced without resorting to a formal rate case But no such change can occur unless either the utility company or some other party or group of parties, including the regulatory commission or its staff, takes some definite and affirmative action Where that happens and there is some objection, the basis for a rate case is created

Background of the Rate Case

During the early years of regulation, the utility rate case was a relatively simple proceeding compared with what it has become under present-day circumstances The utility company usually filed its rate schedules with the state regulatory commission If there were no objections, the rates became effective If there was opposition, there followed a period of examination of the general or specific questions raised by the objection

Usually the objections came from the utility s own customers or from the commission itself or its staff The number of parties involved was few There were hearings, and eventually, a decision and occasionally, an appeal to the courts The general interest was typically limited to the utility s service area and the questions or issues raised were few and easily identified Were the proposed rates too high? If so, by how much? Or were they unfavorable to a particular group or area? If so, in what way?

Sometimes the cases were started by parties seeking to lower rates These might include customers or a class of customers, cities or localities served, the commission itself or its staff, or some aggrieved industry Again, the issues were few and easily identified There was understandably some local interest and publicity But the overall arguments revolved about basic matters such as rate base, return, and revenue requirements There was proper

attention given to the rate structure and this commonly completed the extent of the inquiry

Over the last decade, rate proceedings have become increasingly complex, often lasting for weeks and utilizing extensive expert testimony and computer models The scope of cases has also expanded as commissions consider more and more issues once thought to be solely within management s discretion

Environmental protection and the social concerns for the poor and the aged now characteristically make their presence felt in the modern major contested utility rate case Matters of rate design previously left to utility management are now closely examined and debated by conflicting groups as part of the rate case which the commissions must decide Load forecasting and the planning of a utility s future capacity needs has also become an issue in rate proceedings—an issue that is both technical and controversial

It is interesting to note the accelerating pace of changes in rate case methodology It took fifty years (roughly 1900-50) before a generally accepted pattern of rate base valuation was devised It took about twenty five years (1940-65) for the compilation of acceptable expense and accounting regulatory rules to be established Today the pace of change has escalated to a level never before experienced Issues of major importance in the determination of rates emerge over periods of a few short years The level of sophistication required of regulators, their staff, and utility company management continues to increase

Initiating Changes in Rates

When a utility company files a proposed change in its rates, it is generally in the form of what is known as a ***tariff*** If, after a short specified waiting period (for example, thirty days), no question or objection is raised, that filed rate or tariff becomes effective This is more or less normal procedure for minor changes or for a rate schedule of an entirely new, and probably limited, class of service When the proposals involve substantial rate or class changes, the commission is likely to order a suspension in the time limit (or a delay) before the changes may become effective

A suspension gives the commission an opportunity to analyze the proposed changes The suspension period varies among the states from thirty days to one year, with three months being the most frequent Based on this analysis, the commission may decide either to permit the rates to go into effect, as filed, or to negotiate with the company, on an informal basis, for some further

changes or adjustments in the proposals As a third choice, the commission may decide to order an investigation or hearing on the proposed changes

If, in following the second course, the negotiations for changes do not result in a satisfactory agreement between the commission and the company, the commission may then follow the third course and order a public hearing When this happens, the rate case officially begins As it is initiated by the utility company, the company has what is known as the burden of proof" to justify the proposed changes

Let us assume that it is the utility company which takes the first steps leading up to the rate case (and not some other party or the commission) Here, the utility must take on the role of a ***petitioner*** or ***applicant*** There are several other ways in which rate case proceedings may originate With some variation in state laws, a consumer, a group of consumers, other groups such as a civic organization, trade association, labor union, or a local political subdivision—such as a city or county government—may initiate a complaint about a utility company's rates This may lead to negotiations with the company and result in a satisfactory adjustment of the complaint, or it may grow into a formal rate case proceeding The burden of proof in the case would generally be on the complainant, unless the commission rules otherwise In actual practice, the utility company would probably have to prepare as complete and thorough a case to defend its existing rates as if it had itself initiated the proceedings as a petitioner or complainant

Rate inquiries may also be initiated by the commission itself This may take either of two forms First, the commission may approve a motion to investigate a company s rates, such motion being made by its staff or one of its own members Or, the commission will issue a "show cause order, which means that the company will be ordered to "show cause" why its rates should not be reduced Both forms have a similar result

In any such proceedings the commission cannot act arbitrarily It must have some evidence that the rates are too high or too low This evidence may be developed by the commission's staff in analyzing the utility s operating results and other data concerning its operations contained in its accounts and reports to the commission When these facts indicate that the return earned by the company in question is higher than a reasonable amount, the commission will start a formal inquiry It is the generally accepted rule that the burden of proof is on the utility in any event

Parties to a Rate Case

Participants in proceedings are called ***parties*** The special names used to denote parties in rate cases are as follows

Applicant, sometimes called ***petitioner***, is usually a public utility company seeking a rate change

Petitioner (where not used in the sense of an applicant seeking a rate change) may be any party who seeks relief under any order or rule of a commission

Complainant is the party who complains to a commission concerning some act, or failure to act, resulting in what is claimed to be a violation of regulatory law In a rate case, it is the party ordinarily seeking a reduction The complainant may be a customer, group of customers, a municipality, or a civic or trade organization, depending on local rules and customs

Respondent is the party against whom a complaint or petition is filed and who is expected to reply or respond to the same Thus, in a rate case originating from a complaint or from commission action, the utility company would be the respondent

Intervenor is any interested party who asks to join in the case, and can show that he or she has enough interest in the outcome to be permitted by the commission to intervene as a party

The Rate Department

Most utility companies have rate departments whose duty is to study and review customer needs under varied conditions, what services customers want or can be persuaded to use at various prices and conditions of service The work of a rate department generally falls into three phases—research, development, and administration These phases may be called by different names in different companies

Rate Research Considerable information is needed to arrive at a satisfactory rate form and to fix the amount and terms of charges which are to be quoted in it The company needs information about its investment and operating expenses, its customer loads and system loads, the relationships between rate levels and the types of rates to be used, system planning and expansion, the value of service to various classes of customers and the costs of competitive services, trends in earnings and costs, and forecasts of future loads Rate rulings contained in commission and court decisions and rates and rate practices of government-owned utilities in the service area (especially important in the case of electric utilities), must also be considered Assembling this information is a continuing task of major proportions

Rate Development This phase mainly concerns the design of the rate structure and rate forms Certain objectives have to be kept in mind These are principally the revenue yields, the needs of the several classes of customers, the reasonableness of rates which win customer approval and commission acceptance, the promotion of greater use of the service, the maintenance of rates that are nondiscriminatory, and the preparation of simple rate schedules and rate forms In addition, the performance of the rate designs must be constantly checked and tested in order to find out how well the objectives above are being reached

Rate Administration This phase of rate making involves proper interpretation and application of the rate schedules Each customer should be on the rate schedule for the class of service which he or she uses The service must be properly measured or metered Rate practices should be kept uniform Administration likewise involves the determination of what rate schedule is applicable to a particular use The classes of service should be clearly defined so that customers do not feel that they are entitled to another class of service which carries a lower rate

The rate department works closely with other departments within the utility to prepare for rate cases Representatives the from accounting, finance, legal, and various operating departments are all involved in the preparation of rate testimony The participation of top management is also particularly vital to the company s successful achievement of objectives in a rate proceeding

The Content of a Rate Case

A great quantity of data and facts are necessary to establish reasonableness of rates Assume that a company has petitioned for an increase in rates or, on the other hand, is answering a commission show-cause order why its general service rate level should not be decreased The material which it will have to prepare will include some, or all, of the following

1. ***Qualifying and historical material***

   (a) Service area maps

   (b) Articles of incorporation

   (c) Financial statements—balance sheet and income and expense statement

(d) History of company—including company organization, customers, quantity of sales, population served, peak loads, etc

❷ ***Rate tariff material***

(a) Existing rate schedules, by class and territory, and any special rates and service tariffs

(b) Proposed rate schedules—given in the same detail as above

❸ ***Rate base material.*** Where a particular type of rate base value is required by law or commission order, as an original cost less depreciation rate base, an exhibit drawn from company records showing plant investment and depreciation accounts is all that might be needed

Where reproduction cost or other alternative measures of cost value are to be used (or requested by the regulatory commission), more elaborate and detailed exhibits will be needed, such as details of various plant facilities, land, right of way and so forth The company must also be prepared to support, if it makes a claim for them, intangible and other property values, such as going concern value, working capital, and so on

❹ ***Operating statistics*** These are usually divided into (1) revenue and (2) expense items Commission practice varies on what should be shown here Some commissions base their judgement on an historic test period Others permit some projection into the future In such event, the estimates of future expense will have to be supported by related data with respect to anticipated prices of fuel, other commodities, and wages Estimates of anticipated sales and revenue will likewise have to be supported by estimates of population, future use, and anticipated economic conditions

Commissions scrutinize certain expenses with care Because there is frequently a great deal of attention given to them, the company will probably have detailed exhibits of taxes, depreciation or any other item which may be especially questioned

❺ ***Economic factors*** These would cover such items as the data in support of the claimed rate of return, cost of capital, changes in price levels, losses of revenue due to regulatory lag, and so on The variety and quantity of material here presented may be quite large and of a technical nature Financial data and analysis are often presented by an outside qualified witness, that is, some independent authority (rate expert, banker, security analyst, etc) not regularly employed by the company

This material cannot be prepared in short order It requires both time and careful work Each segment of it must fit into the whole The case, if the company expects to be granted its increase, must be both complete and convincing The witnesses, whether company officials or outside expert witnesses, must analyze the facts carefully and be completely and thoroughly familiar with them

It follows, therefore, that a well managed utility company will not undertake an application for a general rate increase without careful thought and planning Since this requires considerable time, the need for the rate increase may be anticipated before the actual deficit in earnings goes too far When a company decision is made to apply for an increase, there is also a public relations or publicity program to be considered Some explanation to the public is necessary to prepare customers for an increase in rates and gain their acceptance and goodwill in advance of the trial of the rate case, if it is possible to do so

When Do New Rates Take Effect?

Discussion thus far might lead one to assume that the proposed rates would go into effect when the commission issues its decision on the rate application However, this is not always the case

Recall that when a utility files its proposed rates, the commission can suspend the rates for a certain period of time This suspension period varies from state to state Several states have statutes which permit utilities to begin collecting the new rates automatically if the commission has not acted by the end of the suspension period These rates are subject to refund, with interest, if the commission later determines the rates to be unjust or unlawful

In some instances commissions will allow utilities to enact ***interim*** rates or emergency rates while the rate case is being decided These, too, are subject to refund with interest if the rates are found to be unjust or unlawful The utility has the burden of proof when requesting interim rates *i e* the company will need to show the extent of its financial deficiency and justify its request for the interim rates An often stated reason for interim rates rests in the nature of utility regulation—that rates are set prospectively, not retroactively The utility may not charge higher rates to make up for the revenue lost while the rate case was pending

Utilities may be required to wait a short period of time—such as two weeks or thirty days—before enacting the commission approved rates This time period is for the purpose of notifying

customers of the rate change, usually by mail Where a utility has not requested interim rates pending the outcome of the rate case, commissions have allowed the immediate collection of the new rates upon the utility s showing of good faith

Regulatory lag is the situation created by the time interval between the initiation of a request for a change in rates, and the final action by the commission on that request Rising prices often adversely affect the rate of return, since there is a lag in regulation The rate increase may be justified and eventually granted But if the company must suffer financially from the delay involved in the regulatory process of granting the rate increase, it has lost earnings which it cannot recoup Commissions are not agreed on whether regulatory lag should result in a somewhat higher or "catch up" allowance to be included in determining the rate of return There has been some recognition of this problem in recent rate cases Some companies—arguing that since return is forward-looking, commissions should include an adjustment in their consideration of a proper rate of return—have been successful in obtaining a specific "attrition allowance" to offset the effects of earnings erosion

Appeal and Review

As noted earlier, the special legal status of public utilities carries with it both obligations and rights Although the utility is entitled to rates which will produce a fair rate of return, commissions have traditionally enjoyed broad discretion in setting the proper level of rates There are, however, limits on their actions

The United States Constitution has been interpreted to require that a commission provide adequate notice of its proposed action to the utility and allow the company to present its side There is also the general principle which ordains that rates set cannot be so low as to constitute a confiscation of property without just compensation Additionally, state statutes, which provide the commission with its own legal authority to take binding action, often provide specific rights, such as an enumeration of factors which the commission is required to consider in rate making, the method by which the company s rate base is to be valued, and the manner in which it is to be reimbursed for justifiable expenses Finally, state procedural rules may specify the mechanics of the proceeding what types of evidence may be admitted, filing dates etc

Consequently, a party which believes that the commission has not complied with any of these laws has several avenues of redress The first step usually is to petition the commission for a

rehearing in which the regulator is asked to reconsider that decision Aggrieved parties may also appeal to the courts, but usually only after all remedies at the commission level have been exhausted

Appeal and review are expressly controlled by statutory requirements and by court precedents setting forth what the courts may be expected to do For protection, any party in a rate case will take care to prepare, conduct, and develop a case before the regulatory commission in such a way that it can be appealed, if appeal is later found to be necessary or desirable Not all cases are appealed

When commission decisions are appealed, one basic principle generally observed is that the courts are more concerned with matters of law, than with questions of fact The regulatory commissions are presumed to be able to develop the factual side of the case In rate cases, however, many matters such as 'value' or rate of return require factual considerations by the courts The courts determine whether the legal safeguards against confiscatory rates are met or whether legal requirements protecting reasonable rates have been met Thus, the courts often have to consider facts along with law They have, on occasion, set aside commission orders for lack of factual findings necessary to sustain them

Commission orders may also be set aside by the courts if made without sufficient evidence to support them If the evidence was such that a fair minded commission could not come to the conclusion that was reached, the courts will reverse the commission s conclusion, or set aside its order if based on evidence not legally competent, or if certain facts which should have been considered were excluded Again, if facts which should not legally influence the conclusion of the commission were considered, or if the commission applied a rule found to be inapplicable in determining value or any other matter, the courts will intervene

When a commission order is set aside by a court, it is generally the commission, itself, which is directed to revise its order in conformity with the court s decision In other words, the court does not often substitute its own order for that of the commission This second (or ***remanded***) hearing may or may not involve a rehearing of the entire case

Utility Rate Case Activity in 1990

Rate increases granted to investor owned gas distribution companies totaled $234 9 million in 1990, according to a quarterly AGA survey of 117 gas companies That amount compares with

$165 8 million of rate increases for such companies in 1989 AGA reported *requested* rate increases totaling $524 8 million in 1990 Thus, on average, state public utility commission approved 44 8 percent of distribution company rate requests in 1990 The number of cases resolved during 1990 totaled 26, according to survey data

The average return on equity requested by and approved for the companies was lower in 1990, compared with previous years For the 26 cases resolved in 1990, the average requested return on equity was 13 98 percent and the average approved rate was 12 5 percent ***Regulatory lag***, the time elapsed between the application date and the final order of the rate case, averaged 8 2 months in 1990, exceeding the 6 7 month average posted in 1989

Rate increases granted investor owned electric utilities plunged from $6 5 billion a year in 1981-84 to only $1 8 billion in 1989 Rate increases remained depressed at the level of about $1 8 billion annually during the first half of 1990 1990 rate increases were equivalent to a one percent increase in base rates The average return on equity allowed in rate cases that were decided during the first half of 1990 was 12 8 percent, roughly the same as during the previous three years

According to a survey of 82 sample electric utilities, 1990 saw little relief in the flow of investment write-offs, which totaled $1 76 billion during the first nine months of 1990 This translates into an annual rate of $2 7 billion, which is typical of the six previous years The pressure of adverse rate decisions on electric utilities in precarious financial positions again precipitated a series of dividend cuts and omissions A total of 26 of the 82 sample utilities had cut or omitted their dividend since the beginning of 1984 However, there were also 53 dividend increases among the 82 sample utilities in 1990

What of the future? Most gas and electric utilities reportedly expect little or no rate increases in 1992 due to stable fuel prices and low interest rates According to the National Association of Regulatory Commissioners, any increase power companies might charge would be lower than the inflation rate But bigger increases are expected in the next few years as environmental laws toughen Companies will be spending more on environmental equipment and they will be asking for increased rate relief Electric utilities faced with compliance with new clean air legislation and gas utilities attempting to cleanup former gas facilities will be making increased investments in their systems and will be looking to recover such investments through rates

Review Questions

1 What courses of action may a commission take in response to a proposed rate change? _____

_____

2 Define each of the terms below

Applicant _____
Petitioner _____
Complainant _____
Intervenor _____

3 What is regulatory lag? _____

_____

4 What three general functions does the rate department perform? _____

_____

5 What happens when a commission order is set aside by an appellate court? _____

_____

Answers to Questions in Chapter 24

1 The practice of separating the supply and transportation functions of utilities and individually pricing those services for competitive offering is known as unbundling of utility services

2 The answer is "a

3 Economic development rates are offered with the express purpose of attracting new business and thus creating new jobs and stimulating local investments

4 Standby charges qualify as rates because a utility incurs costs in standing ready to serve all customers at all times Customers should be required to share in recovery of those valid costs associated with the guarantee of sufficient available capacity to meet service demands

5 Price cap regulation sets a ceiling on the actual prices to be charged for utility service, but does not limit the return the utility

may earn based on those prices, Traditional rate of return regulation sets a cap on the return, or profit, to be earned

25 Answers to Questions in Chapter 25

1 A commission may allow the rates to take effect as filed, informally negotiate with the utility for adjustments to the proposed rates, or order a hearing on the proposed rates

2 An applicant is usually a public utility seeking a rate change A petitioner may be any p [illegible] seeks relief from the commission A complainant is a part, [illegible] ho alleges that some action is in violation of the law An intervenor is a party who has a sufficient interest in the case to be permitted to join it

3 Regulatory lag is the situation resulting from the time interval between the initiation of a request for rates and the time final action is taken by the commission on that request

4 The rate department conducts rate research, is responsible for rate development or design, and oversees rate administration

5 Generally, the court will direct the commission to revise its order in conformity with the court's opinion The second or remanded hearing may or may not involve a rehearing of the entire case

Analytic Concepts and Regulatory Tools

NARUC Cost of Service Study and Rate Design
August 1995

COST OF SERVICE STUDY

What is a cost of service study

A cost of service study is nothing more than an allocation of plant and expenses among each class of customers, so that each class is paying it fair share of expenses through rates and charges for service Utility plant and expenses are allocated to cost functions and classifications, the cost functions and classification are then allocated to customer classifications The process attempts to trace the costs for meeting the customers' average and peak use, and costs related to customers meters and services. Ideally, the revenues received from each customer class should equal the cost of providing service to that customer class

Purpose of a cost of service study is to determine what it costs to serve each class of customer

The purpose of preparing a cost of service study is to offer **guidance** in setting rates to be charged for utility service Note the word guidance Rates aren't always set based on the computed cost to serve a particular class of customer Instead, the cost of service study could be used to move the utility's rates closer to "cost-based" rates

Additionally, there are many factors at play when rates are set The regulatory body may be moving toward cost-based rates However, the regulatory body may also favor subsidizing one class of customer by the other classes of customers Lifeline rates are a prime example of subsidization of a class of customers by all other customers Another example is rates intended to encourage conservation Thus, public policy may have a significant effect on rate design

There are two generally accepted cost of service studies methods the Commodity / Demand Method, and the Base / Excess Demand Method

We will prepare a Commodity / Demand Cost of Service study

The Commodity / Demand Cost of Service study differs from the Base / Excess Demand Cost of Service study in the following cost allocation to functions

Commodity-Demand Method	Base-Extra Capacity Method

NARUC Cost of Service Study and Rate Design

Functions for Plant Cost and Operating Expenses

Commodity	Base
Demand	Extra Capacity
Customer	Customer
Fire Protection	Fire Protection

Commodity	**Base**
Costs which vary with with consumption of water, such as power, chemicals, and purchased water	Operation and maintenance costs associated with average demands and consumption
Demand	**Extra Capacity**
Capital cost of plant plus plus operation and maintenance not associated with consumption	Operation and maintenance and capital costs due to demands on system in excess of average demand
Customer	**Customer**
Customer costs without regard to consumption and demand, such as meter reading, billing, and capital costs associated with service lines and meters	SAME
Fire Protection	**Fire Protection**
Costs and expenses due to having fire hydrants on the system Could alsoinclude inside sprinkler systems	SAME

<u>Steps in determining the cost to serve each class of customer</u>

Determining classes of customers means that you have to decide how various customer classes are to be defined. You can separate classes of customers into the following categories:

Residential customers are relatively easy to determine This class of customers is normally classified by the Utility Company as residential, and is billed based on previously approved rate tariffs

Commercial customers are normally customers who sell a product or service to the public, or could be multifamily apartment buildings As with residential customers, the Utility Company normally classifies

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commercial customers, and bills them under a commercial tariff

Industrial customers normally manufacture a product, and tend to be large utility customers The Utility Company via it tariff makes the determination as to which customers are classified as industrial customers, rather then commercial customers, through its tariff classification system

Wholesale water customers normally buy the water for resale This customer classification by the Utility Company should be relatively obvious

Public Authority customers are normally governmental bodies

Irrigation customers would be golf courses, greenbelts, and parks.

Fire Protection will normally be public or private fire protection entities The Water Utility has to supply these customers with relatively large volumes of water for short periods of time The trend to sprinkler systems in residential and commercial buildings is another type of fire protection

Another way to classify customers is based on meter size Customers are classified as the size of the meter they use, regardless of the above classifications or the use to which the water is put

The following pages show the process involved in the completion of a Cost of Service Study, and the development of an appropriate rate design via a diagram

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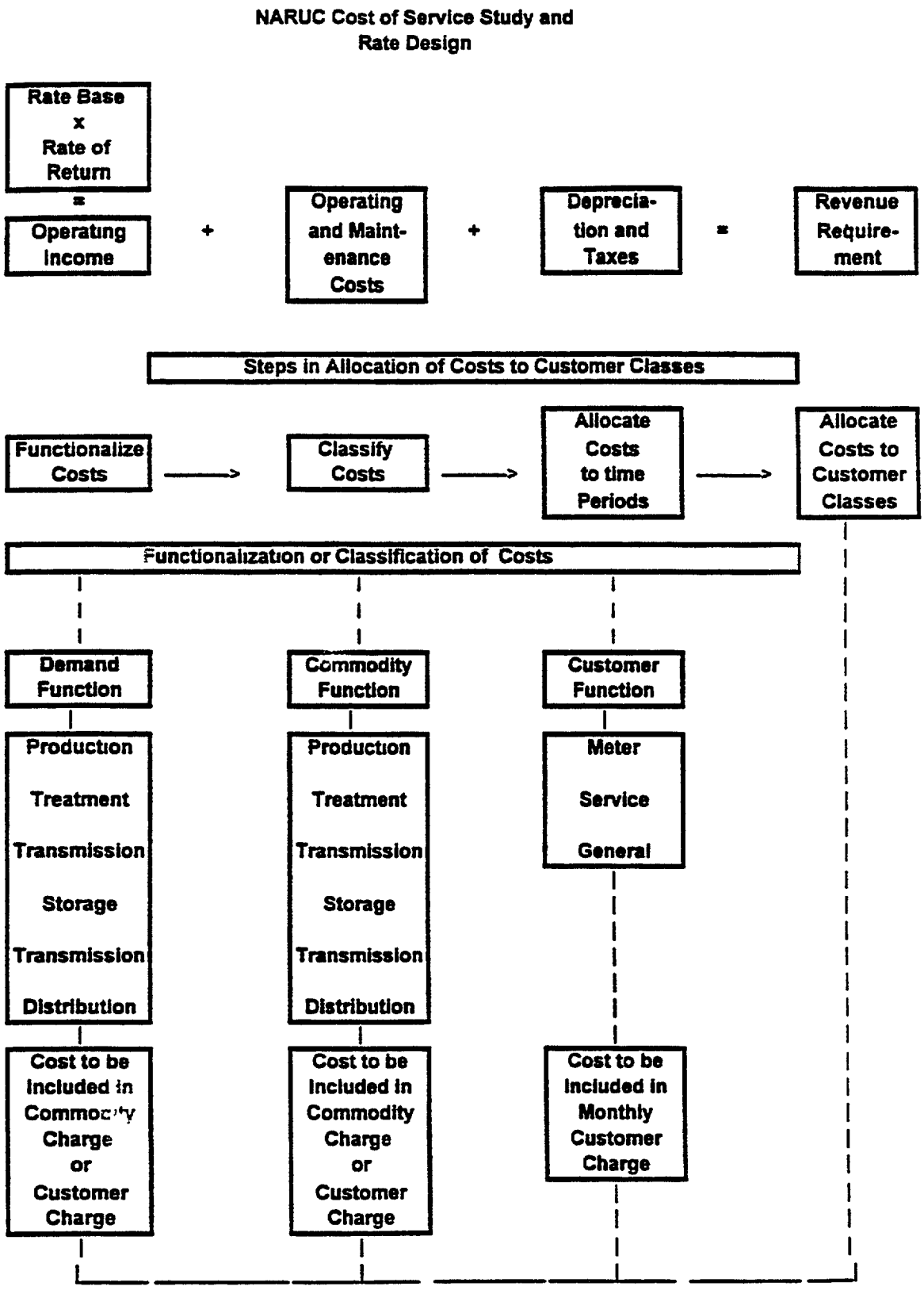
NARUC Cost of Service Study and Rate Design
Rate Base x Rate of Return
=
Operating Income
+
Operating and Maint-enance Costs
+
Deprecia-tion and Taxes
=
Revenue Require-ment
Steps in Allocation of Costs to Customer Classes
Functionalize Costs
Classify Costs
Allocate Costs to time Periods
Allocate Costs to Customer Classes
Functionalization or Classification of Costs
Demand Function
Commodity Function
Customer Function
Production
Treatment
Transmission
Storage
Transmission
Distribution
Production
Treatment
Transmission
Storage
Transmission
Distribution
Meter
Service
General
Cost to be Included in Commodity Charge or Customer Charge
Cost to be Included in Commodity Charge or Customer Charge
Cost to be Included in Monthly Customer Charge

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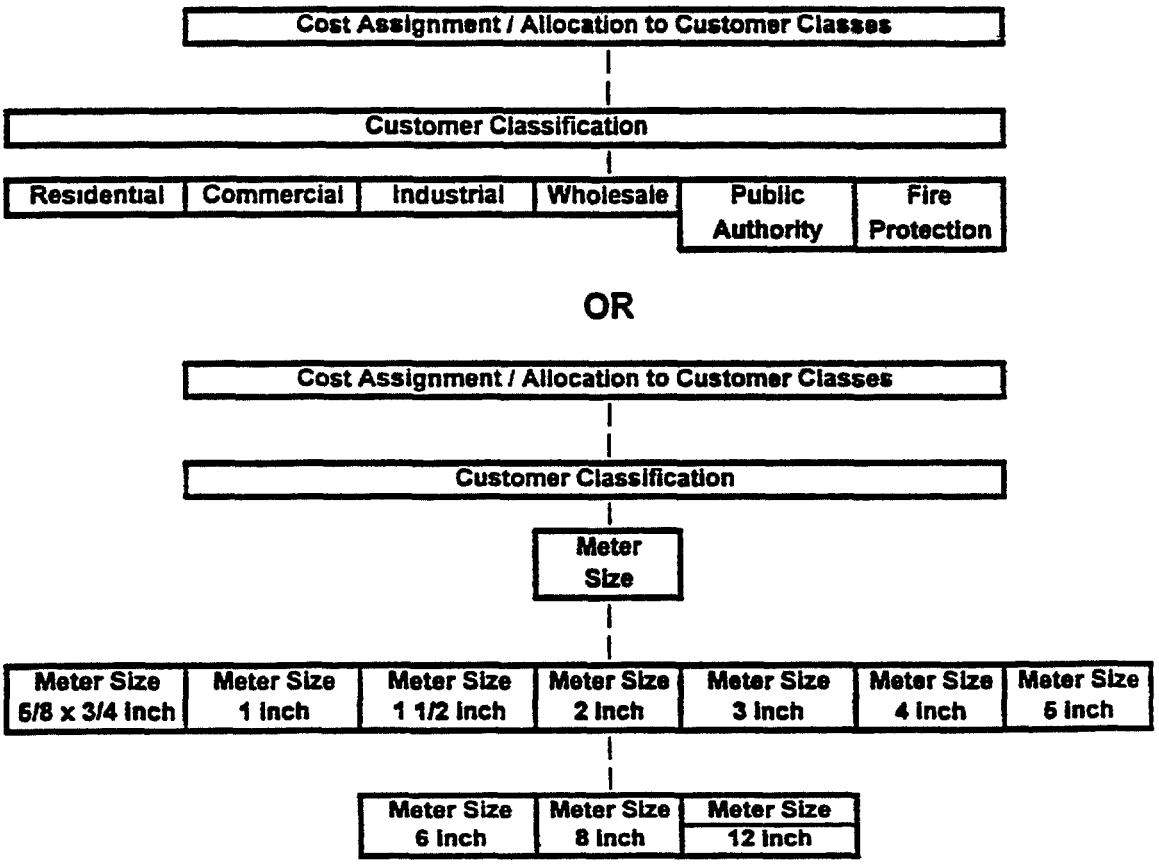
NARUC Cost of Service Study and Rate Design



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The steps in preparing the cost of service study

Allocating net plant (investment) required by each class of customer attempts to allocate the investment needed to serve each class of customer

You will also need to allocate working capital, advances in aid of construction, contributions in aid of construction, unamortized investment tax credits, and accumulated deferred income taxes.

Allocating expenses to cost causers attempts to trace the expense to the class of customer who actually cause the expense

As with any allocation process, the allocation is often subject to different interpretations based on who is making the allocation decision Please note that in this cost of service study we will use some assumptions to speed the process of completing the problem. This class is only a guide to the allocation of plant and expenses

You then match the present rates of the utility to the adjusted expenses, and determine the rate of return on your rate bases prepared for each class of customer Allocation of the present revenues based on cost of service study should be relatively straightforward Once the customer classifications are decided, it is a relatively easy process to account for the revenues at present rates

Determining Proposed Rates

Determining the proposed rates to be charged each class of customer is a very difficult task This is where accounting, economics, engineering, finance, law, rate design, and politics all come together for the major fight on the use to which a cost of service study is to be put

We have learned how to determine the revenue requirement based on rate base, allowable expenses, and an authorized rate of return. Now comes the hard part Who pays what?

Although the cost of service study will produce the revenue requirement by classes of customers (residential, commercial, industrial, meter size, etc), trying to implement rates which will properly recover the revenue requirement from each class of customer becomes extremely difficult In addition to the difficulty in determining the appropriate rates, you may have to recommend major increases for one class of customer, while recommending major rate reductions for another class of customer All classes of customer will be interested in how much of the utility's total revenue requirement they will have to pay

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Gathering data to start the cost of service study

To prepare a cost of service study you need detailed data regarding the utility, including its water usage, expenses, plant assets less accumulated depreciation, working capital, advances in aid of construction, contributions in aid of construction, unamortized investment tax credits, and accumulated deferred income taxes Hopefully, you or Staff personnel have already prepared the rate base, income statement, and cost of capital recommendation. However, the rate base, and income statement and cost of capital are summaries, you will need more detail to prepare your cost of service study

We are going to prepare the Cost of Service Study and Proposed Rates for Newrate Water Company

You should have the following to enable you to prepare the cost of service study:

The Company's **Balance Sheet** to assist you getting the overall picture of the Company assets and what is financing those assets Schedule 1 is the Newrate Water Company's Balance Sheet

You will need an **Income Statement at Present and Proposed Rates** to allocate the expenses, present revenues, and proposed revenues Schedule 2 is the Newrate Water Company's Income Statement at Staff Adjusted Present Rates and Proposed Rates Staff Schedule 5 is the supporting schedule for the proposed rate increase

The proposed total company **Rate Base** is needed because you will must summarize the rate bases you prepared by functions and customer classification to match the overall company rate base. Schedule 3 is Staff Proposed Rate Base for Newrate Water Company Staff Schedule 5 is the supporting schedule for the proposed rate increase

The Company's **Plant Schedule**, or the Staff's plant schedule (Staff Schedule 6) used in preparing the Staff's Rate Base should give you a breakdown of the plant into major functions

Accumulated Depreciation by category of Plant is needed to derive the net investment by function for eventual allocation to classes of customers (See Staff Schedule 6)

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You will need **data on what plant is financed with advances in aid of construction, and contributions in aid of construction** In this class, we are going to make an **assumption** of what plant is financed with advances and contributions in aid of construction In actual practice, such an assumption could cause the cost of service study to be totally meaningless You should attempt to trace the plant financed with advances and contributions in aid of construction, and use the advances and contributions as offsets to the individual plant accounts being allocated to customer classes

You will need a **Cost of Capital or Rate of Return** to prepare the proposed rates to be charged customers Schedule 4 is Staff's Proposed Rate of Return and Capitalization for Newrate Water Company

Depreciation expense for each category of plant is needed when you attempt to allocate the expense associated with the ownership of plant assets The depreciation expenses are shown on Staff Schedule 7

Bill Counts by classes of customers are needed to determine actual and potential demand for allocating plant assets and expenses. The bill counts are labelled as Staff Schedule 8. We will use meter size to classify customers Additionally, many of the allocation factors will be developed based on the number of bills issued, and the quantity of water sold during the test year The bill counts we will use are prepared in 1,000's of gallons Some companies will bill in cubic feet. 100 cubic feet is equal to 748 gallons

Converting Water Utility Expenses and Plant Values to Functions

Functions

The **demand function** attempts to allocate assets and expenses based on the investment in plant and facilities to meet maximum rate at which a utility has to deliver it product You are attempting to determine how the cost of the overall system for production and transmission (and some of the distribution system) can be traced to the demand put on the system at a point in time by each customer class. The cost of the investment necessary for producing the water is a demand cost. The costs of owning utility plant include depreciation and return on investment. The cost of transmission lines to move the water from the point of production to the distribution system is another example of a demand cost These costs would include the depreciation

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on the production plant, transmission lines, and distribution line, and the rate of return on the net investment in the production plant, transmission and distribution lines

The **commodity function** attempts to measure the variable costs associated with supplying water Variable costs are defined as costs that tend to increase or decrease with the amount of water produced Power costs would be an example of a commodity function As the amount of water production increases, the power cost will also increase Chemicals to treat the water are also commodity costs

The **customer function** relates to the costs of having customers on the system These costs are relatively fixed (they don't change with changes in volumes of water produced). Examples of these costs would be billing and meter reading Whether a customer uses 0 gallons, or 400,000 gallons, the Utility Company needs assets, such as office furniture and fixtures, communication equipment, meters, service lines and other plant to serve the customer The depreciation and the return on the above assets are examples of customer functions Meter reading expenses could also be called a step-cost variable, that is, the Utility Company's meter reader only can read so many meters per month, once that limit is reached, overtime may be required, a part-time employee may be needed, or a second meter reader may be needed Or, assume that the Utility Company's computer billing system can only handle 5,000 accounts Adding Customer number 5,001 might mean that the Utility Company has to purchase an new computer billing package, or even a new computer

The **service function** relates to the plant assets and expenses assigned to the service line from the Utility's distribution system to the customers meter The Service function is a subset of the Customer Function

The **meter function** relates to the investment and related expenses in the meter to measure the water flow to the customer Additionally, the costs to read the meter, and prepare the bill for usage are meter functions. The meter function is another subset of the Customer Function.

Computing Allocation Factors to convert Expenses and Plant to Functions

Commodity Allocation Factor

Commodity plant and expenses will be allocated based on total commodity of water used by each class of customer (Schedule 9, with data coming from the Bill Count Schedule, Schedule 8) The allocation factor is computed by dividing the water sold in gallons by class

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of cust , in this case meter size, by the total water sc to all classes, in gallons

Customer Allocation Factor

Custo plant and expenses will be allocated based on the n er of **annual bills** for each class of customers The c tation is annual bills for each class of custo divided by the total of bills for all custo s The allocation factor is from Staff Sched e 9 (Data is from the Bill Count, Schedule 8)

Meter Allocation Factor:

Meter plant and expenses based on investment in meters to serve customers (data is from Staff Schedule 6, and the Bill Count, Schedule 8) We will use year end number of meters The meter cost could be taken from the Company's filed tariff charge to install a meter, or it could be derived by dividing the plant account "Meters" by the equivalent number of meters **Equivalent meters are computed by converting all the meters to one size** If you were converting all meters to the 5/8 x 3/4 inch meter, you would multiply the number of 1 inch meters by the factor of 50/20. 50 is the gallons per minute that a 1 inch meter can flow 20 is the gallons per minute that a 5/8 x 3/4 inch meter can flow Thus, one 1 inch meter equals the eq valent of **2 1/2** 5/8 x 3/4 inch meters A 4 inch me can flow 500 gallons per minute Thus, cc rting the 4 inch meter to equivalent 5/8 x 3/4 i meters would be computed by multiplying the number o inch meters by the factor 500/20. The result is that one 4 inch meter is equivalent to **25** 5/8 x 3/4 meters. The allocation factor is from Staff Schedule 9 The data on the number of meters and cost of the me s are taken from Staff Schedules 6 and 8

Service location Factor.

The services allocation is based on the plant and expenses based on investment in services to serve customers The allocation is based on the number of services year end number) The service cost could be t en fro he Company's filed tariff charge to install a ervice r it could be de ed by dividing the plant account " rice" by the eq ent number of services The alloc on factor is fro aff Schedule 9. The data on the number of servic and the cost of the services are coming from Sta Schedules 6 and 8

Demand Allocat on Factor

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Demand plant and expenses based on investment in system assets to service each class of customer is based on the number year end of meters multiplied by the demand factor, in this case the potential flow through the service line and meter A 5/8 x 3/4 inch meter will flow 20 gallons per minute, while a 1 inch meter will flow 100 gallons per minute A 4 inch meter will flow 500 gallons per minute The result is that one 1 inch meter is equivalent to 2 1/2 meters of the 5/8 x 3/4 inch size, while one 4 inch meter is equivalent to 25 meters of the 5/8 x 3/4 inch size

Schedule 10 is a summary of the allocation factors

Allocating Net Plant to Functions

The net utility plant is allocated to the functions of Commodity, Demand, Customer, Service, and Meter based on the how the net plant is being used to serve customers This shown on Staff Schedule 11. I have listed the functionalization of utility plant on the next page The actual allocation of plant to functions usually is much more difficult than will be encountered in this class

The plant is being allocated net of the accumulated depreciation If you allocate gross plant, you will need to make a separate allocation for the accumulated depreciation The allocation of the accumulated depreciation should be the same as the allocation of the gross plant as to categories of plant

The Organization Cost, Franchise Cost, Land and Land Rights, and Tools and Work Equipment are allocated to the **Commodity Function** (Accounts 301 through 303, and account 343)

Structures and Improvements, Wells and Springs, Electric Pumping Equipment, Water Treatment Equipment, (Accounts 304 through 331) and Transmission and Distribution Mains are allocated to the **Demand Function** An assumption has been made that 30% of the total Transmission and Distribution Mains are is attributable to Distribution Mains The Distribution Mains are allocated to the Customer Function If the Distribution Mains can be segregated in dollars from the Total Transmission and Distribution Mains, the actual cost of the Distribution Mains should be used. (In practice, this is very difficult to do)

The **Customer Function** is allocated 30% of the total Transmission and Distribution Mains (based on the assumption above) and the Office Furniture and Fixtures The accounts being allocated are 331 and 340

The Service's net plant balance is allocated to the **Service Function** The account number is 333

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The M .r's net plant account balance is allocated to the **Meter unction** The account number is 334 Net plant allocated to functions is shown on Staff Schedule 11

The nex ges have the NARUC System of Account Numbers for Plant x in the columns of Demand, Commodity, Customer, Services nd Meter indicates that the plant values could be charged -- these functions

Classification of Water Utility Plant to Functions

Class A

NARUC Uniform System of Account Numbers		Demand	Commodity	Customer	Service	Meter
301	ganization	x				
302	anchises	x				
303	and and Land Rights	x				
304	Structures & Improvement	x		x		
305	Collecting & Impounding Reservoirs	x	x			
306	Lake, River and other Intakes	x	x			
307	Wells and Springs					
308	Infiltration Galleries and Tunnels	x	x			
309	Supply Mains	x	x			
310	Power Generation Equipment	x	x			
311	Pumping Equipment	x	x			
320	Water Treatment Equipment		x			
330	Distribution Reservoirs and Standpipes	x	x			
331	Transmission and Distribution Mains	x	x	x		
333	Services				x	

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Account Numbers		Demand	Commodity	Customer	Service	Meter
	Meter Installation					x
335	Hydrants			x		
339	Other Plant and Miscellaneous Equipment	x	x	x	x	x
340	Office Furniture and Equipment			x		
341	Transportation Equipment			x		
342	Stores Equipment					
343	Tools, Shop and Garage Equipment	x			x	x
344	Laboratory Equipment		x			
345	Power Operated Equipment	x	x		x	x
346	Communication Equipment			x		
347	Miscellaneous Equipment	x	x	x	x	x
348	Other Tangible Equipment	x	x	x	x	x

Source of Account Number and Titles

NARUC Uniform System of Accounts for Class A Water Utility 1984

We will allocate working capital based on expenses which give rise to the need for working capital

Developing the Rate Bases for each Function

After you have allocated the net plant to Commodity, Demand, Customer, Service and Meter functions, you can now prepare rate bases for each function. The rate bases by function will be then allocated to customer classes

The Allocation of Net Plant by Function is used to derive the net plant that is charged to the functions of Commodity, Demand, Customer, Services, and Meter

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The deferred income taxes are allocated to (deducted from) each of the functions based on the plant allocated to each function This assumption is based on the premise that deferred income taxes are applicable to all plant, and thus can be allocated to all plant based on the plant allocated to each function **Please note that this assumption may be invalid**, as deferred income taxes may not be applicable to all plant Additionally, while the deferred taxes may be applicable to all plant, certain plant may have substantially shorter tax depreciation lives than book depreciation lives Assets such as vehicles, computer equipment, tools, office equipment may be depreciated for income taxes purposes over a five to seven year life, while the book depreciation assumed lives may be much longer However, we will use this the assumption that deferred income taxes are applicable to all assets.)

Meter deposits are allocated to (deducted from) the Service and Meter Functions, under the assumption that service and meter plant are being financed with the meter deposits

Advances and contributions in aid of construction are allocated to (deducted from) the Demand and Customer Functions, which includes the transmission and distribution mains It is assumed that the advances and contributions in aid of construction were used to finance the transmission and distribution mains.

The working capital is allocated based on the expenses (other than depreciation, property taxes, and income taxes) charged to the functions of Commodity, Demand, Customer, Service, and Meter

The purchased power and water are allocated to the Commodity and Customer functions

The Commodity and Demand Rate Bases are shown on Staff Schedule 14. The Customer, Service, and Meter Rate Bases are shown on Staff Schedule 15. As a check that the Rates Bases for each of the above functions equals the Newrate Water Company total Rate Base, a cross-check column is used Normally, this would not be shown on the Staff Schedules in the manner in which it is shown on Staff Schedules 14 and 15 I included it to make sure that all the allocations are equal to the total Newrate Utility Company Rate Base

The allocation of working capital is based on the relationship of the percentage of expenses (other than purchased power and water, income tax, property tax, and depreciation) that have been allocated to the functions of Commodity, Demand, Customer, Service and Meter The allocations of working capital based on the percentage of expenses is shown at the bottom of Staff Schedules 14 and 15

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Allocating Operation and Maintenance Expenses to Functions

The numbering system of the NARUC Account Numbers is used to allocate the Operation and Maintenance Expense. Note that on the next page, the **ACCOUNT SUB-NUMBER** serves as the basis for the allocation of the expenses on this schedule

You should check that the expense accounts include only the proper charges that should be included in each account The NARUC numbering system is not a guarantee that each account has only charges that should be included in that account

How do you allocate expenses if the NARUC System of accounts does not use the sub-account number, or if the latest NARUC System of Accounts is not used? The only way this can be done is to determine what types of expenses are being charged to each account As an example, if the Utility Company only has one Wages and Salary Account, you would have to list each charge to this account and the reason for the charge Charges to this account could be for Accounting Salaries, Administrative Salaries, Meter Reader Salary or Wages, Repairs and Maintenance Salaries or Wages. You would need to prepare a list of what types of salaries and wages are charged to the account. Once this list is prepared, you would then need to take each charge to the Salary and Wage Account and classify it as to function (Commodity, Demand, Customer, Service, and Meter) You are attempting to reclassify each account based on the functions included in the account This is rather long and involved process

NARUC Uniform System of Accounts
Expense Categories

Class A NARUC Uniform System of Accounts	Account Sub-Number ---------->	01 Source of Supply and Expenses Operations	02 Source of Supply and Expense Maintenance	03 Water Treatment Expenses Operations	04 Water Treatment Expense Maintenance	05 Transmission & Distribution Expenses Operations	06 Transmission & Distribution Expense Maintenance	07 Customer Accounts Expenses	08 Administration Gereral Expense
601	Salaries and Wages - Employees	601 1	601 2	601 3	601 4	601 5	601 6	601 7	601 8
603	Salaries and Wages - Officers Directors	603 1	603 2	603 3	603 4	603 5	603 6	603 7	603 8
604	Employee Pensions & Benefits	604 1	604 2	604 3	604 4	604 5	604 6	604 7	604 8
610	Purchased Water								
615	Purchased Power					615 5		615 7	615 8
616	Fuel for Power Production					616 5		616 7	616 8
618	Chemicals	618 1	618 2	618 3	618 4	618 5	618 6		
620	Materials and Supplies	620 1	620 2	620 3	620 4	620 5	620 6	620 7	620 8
631	Contractual Services - Engineering	631 1	631 2	631 3	631 4	631 5	631 6	631 7	631 8
632	Contractual Services - Accounting	632 1	632 2	632 3	632 4	632 5	632 6	632 7	632 8
633	Contractual Services - Legal	633 1	633 2	633 3	633 4	633 5	633 6	633 7	633 8
634	Contractual Services - Management Fees	634 1	634 2	634 3	634 4	634 5	634 6	634 7	634 8
635	Contractual Services - Other	635 1	635 2	635 3	635 4	635 5	635 6	635 7	635 8
641	Rental of Building / Real Property	641 1	641 2	641 3	641 4	641 5	641 6	641 7	641 8
642	Rental of Equipment	642 1	642 2	642 3	642 4	642 5	642 6	642 7	642 8
650	Transportation Expenses	650 1	650 2	650 3	650 4	650 5	650 6	650 7	650 8
656	Insurance - Vehicle	656 1	656 2	656 3	656 4	656 5	656 6	656 7	656 8
657	Insurance - General Liability	657 1	657 2	657 3	657 4	657 5	657 6	657 7	657 8
658	Insurance - Workman's Compensation	658 1	658 2	658 3	658 4	658 5	658 6	658 7	658 8
659	Insurance - Other	659 1	659 2	659 3	659 4	659 5	659 6	659 7	659 8
660	Advertising Expense								660 8
666	Regulatory Commission Expense Amortiztion of Rate Case								666 8
667	Regulatory Commission Expense Other	667 1	667 2	667 3	667 4	667 5	667 6	667 7	667 8
670	Bad Debts							670 7	
675	Miscellaneous Expense	675 1	675 2	675 3	675 4	675 5	675 6	675 7	675 8

Source
Uniform System of Account for Class A Water Utility 1984 Page 138 - 139

Staff Schedule 12 contains the allocation of operation and maintenance expenses to functions We used the sub-account numbers to allocate these expenses

Allocation of Property Taxes to Functions

Property taxes are allocated to the functions of Commodity, Demand, Customer, Service, and Meter, based on the **net plant allocated to each of these functions** The assumption here is that the property taxes are caused by owning plant.

Allocation of Depreciation Expense to Functions

The allocation of depreciation expense should be done with the same allocation factors used for gross and/or net plant Depreciation expense on the utility plant will be allocated on Schedule 13

Summary of Expenses except Income Taxes and Interest

At this point, you have allocated all the expenses (Operation and Maintenance, Depreciation, and Property Taxes), except income taxes and interest to functions

Next we will allocate the expense functions (except Income Taxes and Interest) to customer classes using the class allocation factors (Schedule 16) We can't allocate Interest and Income Taxes to classes of customers, because we have not allocated the rate bases by functions

Converting Functional Rate Bases and Expense to Rate Bases and Expenses by Customer Classes

Functional Rate Bases to Customer Classification Rate Bases

The allocation factors from Staff Schedule 10 (Summary of allocation factors) are used to allocate the Functional Rate Bases to Customer Classification Rate Bases. The totals of net plant, advances and contributions in aid of construction, customer meter deposits, deferred income taxes, and working capital are allocated to each customer class, which in our problem consists of customers classified by customers taking service from 5/8 x 3/4 inch meters, 1 inch meters, and 4 inch meters I have included a column at the right side on Schedule 16 to total each component of rate base, as a cross check that the total of the rate bases charged to customers taking service from 5/8 x 3/4 inch meters, 1 inch meters, and 4 inch meters equals the Newrate Water Company rate base

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Staff Schedule 16 contains the allocation of functions to customers for computing the rate base attributable to each class of customer

Functional Expense classification allocated to Customer Expense Classifications

The allocation factors from Staff Schedule 10 (Summary of Allocation Factors) are used to allocate the Functional Expenses to Customer Classifications based on customers taking service from 5/8 x 3/4 inch meters, 1 inch meters, and 4 inch meters This is shown on Staff Schedule 17

Note that I have a cross check column at the left of the schedule to make sure that the total expenses are being allocated

The next step is to allocate the revenues at present rates to each class of customer taking service

Property Taxes, account 408 11, are allocated to each class of customer (customers on 5/8 x 3/4 inch meters, 1 inch meters, and 4 inch meters) based on property taxes charged to commodity, demand, customer, service and meter functions

Next, Interest Expense is allocated to each class of customer (customers on 5/8 x 3/4 inch meters, 1 inch meters, and 4 inch meters) The allocation is based on the rate bases charged to these same classes of customers The assumption being made here is that interest expense is attributable to assets of the utility company whi h are included in the rate base

Normally, a utility company's income statement contains income taxes expense as an expense deducted prior to deriving operating income, and interest as a an expense after deriving operating income ("below the line"). However, we will use interest expense to derive taxable income on Staff Schedule 17, so that we can allocate the income taxes at present rates. In effect, we will derive net income on this schedule.

This Staff Schedule would not normally be included in the Schedules that are filed with your testimony, but would be used as a one of your work papers

Development of the Rate of Return at present rates by Customer Classification

Continuing with Staff Schedule 17, once we have derived the allocation of interest and income taxes, we can use this same schedule to compute operating income

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Taking the data from Staff Schedule 16, we list the rate base below the operating income for each class of customer, and then divide the customer classification operating income by the customer classification rate base to derive the Rate of Return at Present Rates

Development of the Revenue Requirements at proposed rates by Customer Classification

Still using Staff Schedule 17, we can deduct the rate of return at present rates from the rate of return at proposed rates to return to determine the **Operating Income Deficiency**. The proposed rate of return is from Staff Schedule 4

Multiplying the operating income deficiency by the revenue conversion factor (from Staff Schedule 6) we can derive the **Revenue Deficiency**

Adding the Revenue Deficiency to the present revenues results in the **Proposed Rates** Note that the rates for the customers on the 5/8 x 3/4 inch meters and the 1 inch meters should be increased, while the rates for customers on 4 inch meters should be decreased

Now we are finally ready to design new rates

Rates based on the Cost of Service Study

Developing the Rate Design from the Cost of Service Study

Computation of Monthly Minimums, with or without any water included in the monthly minimum, involves determining how much should be charged monthly to each class customer regardless of the amount of water consumed. The monthly minimum should include all costs which are necessary to bring water to the point of delivery, regardless of use

Referring to Staff Schedule 18, the rate bases allocated to the functions of Customer, Service, and Meter are multiplied by the weighted debt cost to derive the debt component that should be recovered in the monthly minimum charged to customers

The weighted cost of equity times the Customer, Service, and Meter rate bases results in the equity return that should be recovered in the monthly minimums charged to customers The return on equity results in a additional income taxes Thus, the equity return is multiplied by the revenue conversion factor to recover the applicable income taxes

The return on the Customer, Service, and Meter rate bases now consists of the debt return, the equity return, and the applicable income taxes

Next, the expenses which have been allocated to the Customer, Service, and Meter functions are added to the required rate of return The result is the total revenue requirement that should be recovered from monthly minimum billings

To derive the monthly customer charge, the total **customer revenue requirement** is divided by the number of bills The concept here is that billing costs don't increase or decrease due to the size of the meter The cost of billing a customer on a 1 inch or 4 inch meter is the same cost that is incurred in billing a customer on a 5/8 x 3/4 inch meter

The next step in deriving the monthly minimum charges is to divide the **revenue requirement for the service and meter functions by equivalent meters** All meters will be converted to equivalent 5/8 x 3/4 inch meters

The last step is to sum the customer revenue requirement charge per customer and the service and meter revenue requirement per meter to derive the monthly minimum charge for each class of customer, with class of customer being defined as meter size

The computed monthly minimums are

$13 08 for customers on 5/8 x 3/4 inch meters,
$18 46 for customers on 1 inch meters, and
$99 24 for customers on 4 inch meters

No water would be included with these charges. We will handle inclusion of water in the monthly minimum when we compute additional rates

After we have computed the monthly minimum charges based on meter size, we will compute the Average Commodity Cost per unit of water

The process is the same that was used to compute the monthly minimums, except that we will divide by total gallons sold during the test year, including gallons included in the monthly minimum

Referring to Staff Schedule 19, the rate bases allocated to the functions of Commodity and demand are multiplied by the weighted debt cost to derive the <u>debt component</u> <u>or cost</u> that should be recovered in the commodity charges (the rate that is charged per 1,000 gallons of water)

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The weighted cost of equity times the Commodity and Demand rate bases results in the equity return that should be recovered in the commodity charges to customers The return on equity results in a additional income taxes Thus, the equity return is multiplied by the revenue conversion factor to recover the applicable income taxes

The return on the Commodity and Demand rate bases now consists of the debt return, the equity return, and the applicable income taxes

Next, the expenses which have been allocated to the Commodity and Demand functions are added to the required rate of return The result is the total revenue requirement that should be recovered from commodity charges to customers.

The last step is to divide the total revenue requirement from the Commodity and Demand functions by the gallons sold during the test year The result is the **average charge per 1,000 gallons of water** at proposed rates That rate is $0 126452 per 1,000 gallons, with no water included in the monthly minimum

However, applying the average charge per 1,000 gallons of water sold to each class of customer will not produce the proposed rate of return by customer class (meter size) The reason is that we have used average charge per 1,000 gallons We can apply the commodity charges to the water sold to each class of customer, and multiply the monthly minimums times the customers in each class as a test of whether or not the average commodity rate produces the correct rate of return

Referring to Staff Schedule 20, the top part of this schedule shows the revenues from the monthly minimums and the commodity charges using the average commodity charge. As you can see, the rates of return by customer class, 5/8 x 3/4 inch, 1 inch, and 4 inch meter classes are above and below the overall cost of capital for Newrate Water Company, which is 11 7153%

The way to derive the **commodity rate needed to fulfill the revenue requirement by class of customer** is to determine the revenue requirement by trial and error for each class of customer, and then to subtract the monthly minimums from the total revenue requirement The remainder is divided by the gallons sold to each class of customer to derive the commodity rate. Staff Schedule 21 has the revenue requirement by class of customer to achieve the required rate of return by customer class

Staff Schedule 22 derives the needed commodity rate by class of customer The computation is to deduct the revenues

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produced by the monthly minimums from the total revenues needed by class of customer The remainder is divided by the gallons sold to each class of customer to derive the charge per 1,000 gallons The computed commodity rates necessary to meet the revenue requirement for each class of customer are

$0.64271 for customers on 5/8 x 3/4 inch meters,
$0.85295629 for customers on 1 inch meters, and
$0.0 540818 for customers on 4 inch meters

RATE DESIGN

Goals of Rate Design

Meeting the Revenue Requirement.

This should be your first goal. Your proposed rates must generate the revenue requirement

Fairness to customers

The proposed rates should treat the customers fairly, and allow the customer options for different rates (such as off-peak rates, etc) which can help the customer manage his or her bill

Value of Service

The customer should be assured a quality product or service for the increased rates If the customer is required to pay more, the customer will [illegible]ume that the quality of service will be as high or higher than is presently experienced

Ease of Customer Understanding.

This concept is a part of the goal of fairness to customers The customer should be able to understand the rate, and meet the goals of the proposed [illegible]te, whether the goals are conservation, reduction o[illegible]eak use, or a better load curve The proposed rate should [illegible] understandable to the customer in regard to the cause of the cost and the computation of the bill that the customer will be paying. If the customer can't determine how the bill is derived, the customer has no chance to control their higher bill by modifying usage, and the goal of the proposed rate will not be met.

Revenue Stability

As stated above, the proposed rates should actually generate the revenue requirement If the total rate increase is placed in the highest usage block, chances are that the water utility will never recover the revenue requirement due to conservation, and/or weather changes If conservation is a goal of the proposed rates, an elasticity adjustment should be factored into the rates to account for the lower volumes of water that are likely to be sold Otherwise, the authorized rate of return cannot be earned Expenses which are expected to decrease, due to lower production of water related to the conservation effort, should also be decreased

Avoidance of rate shock to a class of customers

This goal is often difficult to meet Major changes in rate design should be avoided if rate shock is the result Instead, the proposed rates should move toward the desired goal in gradual steps Thus, it may take two or three rate cases to get to the desired rates Or step rate increases could be proposed After certain conditions are met, such as plant investment, or passage of time, the rates are increased in steps

Ease of Administration and Customer Impact

The utility company should be required to educate its customers on the new rates Customer education should consider topics of rate shock, elasticity of demand, and conservation

A bill comparison should be computed to show the dollar and percentage increase at various levels of consumption Don't get lost in the percentage increases Take into consideration that if the percentage increase is high, say 50%, but the dollar increase is low, say $1.00, that you have public relations problem, not a rate problem

Recognizing Elasticity of Demand

Elasticity of demand means that as the price per unit goes up, consumption goes down It is assumed consumption never goes to zero, but elasticity can be substantial As adjustment which reduces the consumption due to elasticity, and the expenses which would also be reduced should be used in the rate case

Conservation

Conservation, particularly if water is in limited supply, is a valid goal The conservation may only be needed for summer months, or it may be needed year-round.

Recognizing seasonal va on of costs

If the water utility is located in a service area which is served by a summer peaking electric power company, it is assumed that the total costs, and the costs per unit of output (water), will be higher in the summer period

Additionally, you may encounter a situation where the customer usage and/or number of customers varies substantially from one season to another. This is particularly true of vacation areas

Using the Consolidation Factor to Compute Revenue Requirements

The Consolidation Factor is a means to quickly determine the revenues produced by various rate design possibilities. At any point of the consolidation factors, the proposed revenues can be computed by multiplying the customer bills by the proposed monthly minimums, and multiplying the consolidation factor times the proposed commodity rates **The consolidation factor represents the billable gallons at any line of the bill count.**

As an example, using the Bill Counts and Consolidation Factors from the 5/8 x 3/4 inch meters, if we proposed a monthly minimum of $15 00 which includes 3,000 gallons of water and a commodity rate of $0 85, the proposed rates would produce revenues of $406,723 The computation is

Revenues from Proposed Monthly Minimums:	
1,408 customer bills x $15 00 per month x 12 months =	$253,440
Revenues from Proposed Commodity Rates (Final Consolidation Factor - ((Consolidation Factor at 2.5 + Consolidation factor at 3 5)/2)) x $0.85 = **(A)**	153,283
Total Revenue from proposed rates =	$406,717
(A) Final Consolidation Factor	226,871.0
((Consolidation factor at 2.5005 + Consolidation factor at 3.5005)/2) =	-46,545 5
	180,325.5
Proposed Commodity Rate per 1,000 Gallons	$0 85
Commodity Revenues	$153,277

Final Consolidation Factor		226,871 0
Consolidation factor at 2 5005	39,208	
Consolidation factor at 3 5005	53,883	
Subtotal	93,091 / 2=	-46,545 5
Total billable gallons		180,325 5

We had to average the consolidation factors at 2.5 and 3.5 (1,000 gallons) because we are using the midpoints for usage By averaging 2 5 and 3.5, we derive the consolidation factor for usage of 3 0 (three thousand gallons) Our proposed rates of $15 00 per month includes 3,000 gallons of water, which are not billable gallons (See Staff Schedule 23 for the Bill Comparison)

Remember when you include 3,000 gallons of water in the monthly minimum charge of $15 00 to customers, the amount that goes to recover the customer costs is less that $15 00 The cost to produce and deliver the 3,000 gallons of water is a commodity/demand cost.

Or, suppose that you knew what the total revenue requirement was for a particular class of customer. You could determine the revenues from the monthly minimums, subtract that from the total revenue requirement, and then divide the remaining revenue requirement by the consolidation factor to derive the commodity charge.

Computing the Consolidation Factor

The consolidation factor is computed using the following equation

((Total bills - Cumulative Number of bills, **at that level of usage**) multiplied by midpoint usage) + cumulative gallons

To compute the consolidation factor at 12.5005 (1,000's of gallons of water), the computation is

((16,896 total bills - 9,0011 cumulative bills at usage of 12.5005) x 12.5005 usage level) + 54,292 cumulative gallons at 12 5005 usage level =

((16,896 -9,001) x 12 5005) + 54,292 =
((7,895) x 12 5005) + 54,292 =
(98,691 44) + 54,292 =
152,984

(See Staff Schedule 8-A-4)

Other examples using the Consolidation Factor

Using the Consumption and the Consolidation Factor for the 5/8 x 3/4 inch meter

If revenue needed from customers on 5/8 x 3/4 inch meters is $350,000, and the proposed monthly minimum is $13 50, with **zero gallons included in the monthly minimum**, what is the needed commodity rate per 1,000 gallons of water?

Total Revenue Requirement	$350,000
Less:	
Revenues from Proposed Monthly Minimums. 1,408 customer bills x $13.50 per month x 12 months =	-228,096
Revenues needed from commodity revenue	$121,904
	========
Revenues needed from commodity revenue	$121,904
Divided by	
Total Consolidation Factor of	226,871 =
Commodity Rate of	$0 537327379

(See Staff Schedule 24)

If revenue needed from customers on the 5/8 x 3/4 inch meters is $400,000, and the proposed monthly minimum is $11 00, with **five thousand gallons included in the monthly minimum**, what is the needed commodity rate per 1,000 gallons of water?

Total Revenue Requirement	$400,000
Less	
Revenues from Proposed Monthly Minimums 1,408 customer bills x $11.00 per month x 12 months =	-185,856
Revenues needed from commodity revenue	$214,144
	========
Revenues needed from commodity revenue	$214,144
Divided by	
Total Consolidation Factor of	226,871
Less	
Consolidation factor at 4 5 plus Consolidation factor at 5 5 divided ((67,778 +80,887)/2) =	74,332 5
	152,538 5
	=========

$214,144 / 152,538 5= $1 403868 per 1,000 gallons

(See Staff Schedule 25)

Suppose you want an inverted rate, i e rate per 1,000 gallons increases as consumption increases The revenue requirement is $400,000 The monthly minimum is $12 00, with zero gallons in the monthly minimum The first 5,000 gallons are to be priced at $0.56 What price do we charge for gallonage usage over 5,000 gallons?

Total Revenue Requirement	$400,000
Less	
Revenues from Proposed Monthly Minimums	
1,408 customer bills x $12 00 per month	
x 12 months =	-202,752
Revenues needed from commodity revenue	$197,248
	========
Revenues needed from commodity revenue	$197,248
Less Revenues at 5,000 gallons or lower consumption	
Consolidation factor at 4 5 plus	
Consolidation factor at 5 5 divided	
((67,778 +80,887)/2) x $0 56 =	41,626 2
Revenues needed from consumption	
at 5,001 or higher usage	$155,621.8
Divided by	
Total Consolidation	
Factor of	226,871
Less	
Consolidation factor at 4 5 plus	
Consolidation factor at 5 5 divided	
((67,778 +80,887)/2) =	74,332 5
	152,538 5
	=========

$155,621 8 / 152,538 5= $1 020213257 per 1,000 gallons

(See Staff Schedule 26)

Types of rate design

A **Flat Fee**
A monthly dollar amount, regardless of consumption
Normally used when meters are not on the distribution

system. Customer receives no price signal, and thus will over consume, rather than conserve

If the revenue requirement from the 5/8 x 3/4 inch meter users is $400,000, the monthly flat fee would be $400,000 / (1408 x 12) = $23 67

B **Uniform rate**
The price per 1,000 gallons is constant as consumption increases The simplest uniform rate would include no monthly minimum charge, and all gallonage would be priced at the same rate Works well for conservation

If the revenue requirement from the 5/8 x 3/4 inch meter users is $400,000, the monthly uniform rate would be $400,000 / 226,871 units of 1,000 gallons = $1 7631

C **Decreasing block rates**
The price per 1,000 gallons decreases as consumption increases Used for large-volume customers As an example, the monthly minimum is $11 00 with no water included in the monthly minimum. The first 20,000 gallons are priced at $1 00 per 1,000 gallons (first block), while all water thereafter is priced at $0.53779662 per 1,000 gallons

If the revenue requirement from the 5/8 x 3/4 inch meter users is $400,000, the monthly uniform rate would be $400,000 less the monthly minimum charges of $185,856

The consolidation factor for 20,000 gallons usage is
Consolidation factor at 19 5 = 197,015
Consolidation factor at 20 5 = 201,656
Subtotal 398,671 /2 =
Consolidation factor at 20 0 = 199,335 5 x $1 00 = $199,335 5

Total Revenue Requirement	$400,000
Less	
Monthly Minimums Revenue	185,856
First Block Revenues	199,335 5
Revenues needed from Second Block	$14,808 50

Second block gallonage =	
Total Consolidation factor	226,871
Less Consolidation factor at 20,000 gallons	199,335 5
Second block gallonage equals	27,535 5

$14,808 50 / 27,535.5 = $0 53779662

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(See Staff Schedule 27)

D. **Increasing block rates**
Price per 1,000 gallons increases as consumption increases Used for reducing average and peak usage

Assume the revenue requirement for the 5/8 x 3/4 inch meter customers is $400,000. The monthly minimum is $10 00, and includes no water The first 15,000 gallons are to be priced at $0 75 What price has to be charged for usage over 15,001 gallons?

The consolidation factor for 15,000 gallons usage is
Consolidation factor at 14 5 = 168,306
Consolidation factor at 15 5 = 174,971
Subtotal 343,277 /2 =
Consolidation factor at 15 0 = 171,638 5 x $0.75 =

$128,728 88

Total Revenue Requirement	$400,000
Less	
Monthly Minimums Revenue	168,960
First Block Revenues	128,728 88
Revenues needed from Second Block	$102,311.12
Total Consolidation Factor =	226,871
Less	
Consolidation Factor at 15.0	171,638 5
Billable gallons above usage of 15,001 =	55,232 5

$102,311 12 / 55,232 5 = $1 8523717

(See Staff Schedule 28)

E **Fixture rate**
This rate is based water-using fixtures on the customers premises. Used when meters are not on the system

F. **Seasonal differential rates**
Normal seasonal differential rates are based pm winter / summer The winter months normally could be defined as October through May, and the summer months would be June through September

This type of rate recognizes the higher costs of producing and distributing water in the high usage months If the seasonal differential is set high enough, resulting conservation would mean less

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investment in peaking production, transmission, and distribution plant This method of pricing recognizes the differences in the cost of production at peak and less than peak months

The consolidation factor cannot be used in its present form to develop summer and winter rates You would need to compute separate consolidation factors for October through May, and June through September.

G **Excess use**
Excess use is defined as usage above the average used during the winter months The purpose is to reduce the peak use

H **Scarcity**
Rates are determined on cost of developing new supply Rates are set at the cost of the next unit to be produced

I **Conservation rates**
Conservation rates could be the inverted block rate, seasonal differential rates, or excess use rates

J **Lifeline rates**
The rate for the quantity of water defined as "necessary" for the customer is set at a low rate The rate for water above the "necessary" water is set at a higher price This rate design is sometimes used for low-income customers, so that they are not unduly burdened by high prices All water used above the "necessary" water subsidizes the lifeline rate for "necessary" water

Sources of data on cost of service studies and rate design·

Cost Allocation and Rate Design for Water Utilities, American Water Work Association, Research Foundation

Manual of Water Supply Practices, Alternative Rates AWWA M34, American Water Work Association

Cost Allocation and Rate Design for Water Utilities, The National Regulatory Research Institute

Utility Rates, Public Utilities Reports Guide

Manual of Water Supply Practices, Water Rates AWWA M1, American Water Work Association

BASIC PRINCIPLES OF APPLIED ELECTRICITY PRICING
COST OF SERVICE RATEMAKING

1995 NARUC ANNUAL REGULATORY STUDIES PROGRAM

Martin Blake

1 Revenue requirement includes

A. Operation and maintenance expenses

B Return on investment (rate base x rate of return)

C Depreciation (return of investment)

D Income taxes

E Other taxes (property taxes, etc.)

2 Test year - Any 12-month period used by a regulatory commission as a basis for evaluating the rate base, depreciation, taxes and operating expenses of the utility Ideally, the test year will reflect revenues and expenses that will occur during the time period when the rates will be in effect.

A. Historic - A recent 12 month period which reflects the actual results of operations

B Future or forecasted - A future 12 month period which reflects the anticipated results of operations

- May do a better job of reflecting revenues and expenses when the rates will be in effect

- May be disagreements among the parties regarding their estimates of revenues and expenses

- Usually includes some examination of a historical period to determine if costs in each account have been reasonable and prudently incurred

3 Imprudence and disallowance - Based on Bluefield Waterworks and Improvement Co v West Virginia Public Service Commission, (262 U S 679, 1923), and Federal Power Commission v Hope Natural Gas Company (320 U S 391, 1944), a utility has the right to recover its prudently incurred expenses and earn a fair return on its

investments of capital used to provide service to ratepayers Each element in revenue requirement must be judged in light of prudence, i e was the expenditure prudent or reasonable In order to disallow an expenditure, there must be a finding that the expenditure was imprudent or unreasonable Reasonableness and prudence probably are best judged not in hindsight but based on an evaluation of the facts available at the time the decision was made

The terminology of "above the line" and "below the line" flow from the determination of reasonableness and prudence "Below the line" refers to expenses incurred by the utility that will not be allowed to be recovered from ratepayers "Above the line" refers to expenses that will be allowed to be recovered from ratepayers

4 Operation and maintenance expenses - A group of costs incurred by a utility composed of production, transmission, distribution, customer accounting and collections, sales, and administrative and general expenses These costs include salaries, fuel, rent, advertising, repair and maintenance, right of way payments, legal fees, consulting fees and other cost elements

A. Types of costs

1 Production Expenses - A group of expenses incurred in the generation of electricity These include the cost of fuel for generators, salaries, repair and maintenance of generating equipment

2 Transmission Expenses - A group of expenses incurred in the process of moving electricity from generating plants to distribution substations These costs include repair and maintenance of lines, rent or right-of-way payments, and salaries

3 Distribution Expenses - A group of costs incurred in the process of moving electricity from substations to consumers These costs include salaries, repair and maintenance of distribution equipment

4 Customer Accounting and Collection Expenses - These are the costs that are incurred due to billing customers and keeping track of all of the customers' records

5 Sales Promotion Expenses - These are a group of expenses incurred due to advertising, promotional practices, creating goodwill, and influencing the market.

6 Administration and General - A group of expenses incurred in the process of managing the utility's short and long run plans and day-to-day business

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B Pro forma adjustments - Adjustment of test year operation and maintenance expenditures for appropriate known and measurable changes For example, suppose wages to union workers were $25 million during the test year and since the end of the test year, the union obtained a new contract granting a 5% across-the-board wage increase It would be appropriate to adjust test year wages upward by $1.25 million (05 X $25 million)

C. Non-recurring expenses - Costs which a utility incurs on a one-time basis or at widely spaced and irregular intervals An expense cannot be disallowed or excluded from test year expenses simply because it is non-recurring A finding of imprudence or unreasonableness is needed in order to disallow such an expense Such non-recurring expenses are usually spread over a period of time rather than being expensed in just one year For example, a one-time cost of downsizing a utility's workforce may be amortized over a 3 year or longer period

5 Determination of rate base

A. Net original cost rate base - The sum of the construction and acquisition costs of a utility's plant, equipment, land and intangible capital used and useful in serving the public, including additions and betterments, minus accrued depreciation at the time of the rate base determination.

B Fair market value - A composite measure of determining rate base which considers accrued depreciation on actual cost, reproduction cost when new less depreciation and other factors, each weighted according to their effect on value

C Reproduction Cost - The cost of duplicating the existing plant and equipment at current prices

D Replacement Cost - The cost of duplicating the old plant with the modern technology version

E When to measure rate base

1 End of period rate base - Value of the rate base at the end of the test year This concept typically is used in conjunction with a historical test year.

2. Average rate base - Average of the rate base throughout the test year This concept typically is used in conjunction with a future or projected test year

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F Construction Work In Progress (CWIP) - An acco which includes the total of f ds expended for utility plant under constru n, but not yet placed in serv CWIP may or may not be included in th rate base, but ultimately, wher laced in service, it will become part of the physical plant. Inclusion of CWIP in rate base can be justified because it mitigates the size of the rate increase necessary when the plant is completed and placed in rate base Additionally, making consumers pay in advance for assets that will serve them later sends a price signal about future costs to consumers who can then begin a process of adjusting their demands to the new price level Those who oppose including CWIP in rate base claim that it is an unfair burden on current ratepayers to include in rate base plant which is not yet used and useful

G Allowance for Funds Used During Construction (AFUDC) - A credit to the income statement which recognizes the cost of funds dedicated to construction activities during the construction period This credit to the income statement is offset by concurrent charges to the utility plant accounts This has the effect of including the cost of financing construction as a component of utility plant. As a consequence, since utility plant is subject to depreciation, AFUDC is recovered from ratepayers over the service life of the plant to which it applies in the form of depreciation. AFUDC allows the utility to recover costs of the plant and to earn a return on capital costs incurred while a facility is under construction It also removes from the income statement the effects of exp nses that have nothing to do with operations for the current year

6 Rate of Return - The ratio of a utility's total earnings to its rate base, expressed as a percentage It is the percent of the rate base the utility is allowed to collect in order to pay for the cost of net invested capital The criteria used to establish a fair rate of return include A) the cost of capital, B) comparable returns and C) the attraction of capital

A. Cost of Capital

1 Capital Structure

a. Debt Includes outstanding mortgage bonds, debentures, advances from associated companies and notes

b Preferred stock - Capital stock to which preferences or special rights attach particularly as to dividends and/or proceeds in liquidation. Preferred stockholders usually have a contractual agreement specifying the rate of interest or dividends to be paid and in the event of liquidation they receive payment before common stockholders

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c. Common stock (equity) - Represents the ownership in a corporation. Common stock is not limited or preferred as to distribution of earnings or assets

2. Determination of return on equity

a. Discounted cash flow (DCF) - DCF analysis is based on the assumption that the price of a common share equals the present value of the sum of all future income to be received from the share Assuming that the dividend payout ratio, earnings price ratio and growth rate remain constant the

$$ROE = \frac{d}{p} + g$$

where

ROE = expected return on equity,
d = dividend per share,
p = price of the stock,
g = expected annual growth in dividend or market price of the stock

b Risk premium approach - This approach is based on the theory that the required rate of return is higher for riskier securities Thus, the equity of a utility should have a higher required return than its debt The differential between the cost of equity and debt is the required premium for enticing investors to accept the greater risk associated with equity This approach can be represented as

$$ROE = CD + RP$$

where

ROE = required return on equity,
CD = long term cost of debt,
RP = risk premium

c Capital Asset Pricing Model (CAPM) - This approach is based on modern portfolio theory Return on investment consists of two parts 1) a risk free return and 2) an additional return to

compensa for risk. Risk is measured by comparing the volatility . return on a utility's stock with return in the market as a whole This approach can be expressed as

$$ROE=r_f+B(r_m-r_f)$$

where·

ROE = expected return on equity,
r_f = expected risk free return,
r_m = expected stock market return,
B = utility stock's expected relevant market risk beta.

B Comparable Returns - Compares the utility's rate of return with the rate of return in other enterprises regulated and unregulated) with comparable risk

C Attraction of Capital - An estimate is made of how high the rate of return should be in order to motivate capital suppliers to be forthcoming with the necessary amounts of capital investments the utility must have in order to continue providing a service to the public.

D Equity gross up - Because the utility must pay state and federal income taxes on its net earnings, net earnings must be "grossed-up" for state and federal taxes so that shareholders have the opportunity to earn the allowed rate return after corporate income taxes have been paid For example, if the allowed return on equity is 12% and state and federal taxes combined are 42%, the before-tax return on equity must be 20 7% [12 / (1-0 42)]

7 Depre ation - Charges made against income to distribute the cost of depreciable plant, less estimated net salvage, over the estimated useful life of the asset Through this charge against income, shareholders receive the return of their investment

A. Straight Line Method - The cost of the asset less estimated salvage is allocated in equal amounts over the asset's estimated useful life

B Accelerated Method - This refers to certain approved methods of computing depreciation allowance for federal and/or state income tax purposes, applicable to plant additions with a useful life or three years or more These

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methods permit relatively larger depreciation charges during the earlier years of the life of the property and relatively smaller charges during the later years, in contrast with the straight-line method, under which annual charges are the same for each year

8 Taxes

A. State and Federal Income Taxes

1 Flow-through Method - Under the flow-through method, decreases in state or Federal income taxes resulting from the use of accelerated depreciation for income tax purposes are carried down to net income in the year in which they are realized This results in tax savings being used to reduce rates in the year in which the savings are received This can cause the price of electricity to fluctuate because of temporary tax savings In a broad sense, the flow-through method is said to apply to any timing difference for which deferred income taxes are not provided

2 Normalization - Normalization spreads tax savings over the life of the property and results in the rates not fluctuating because of temporary tax savings Under normalization, decreases or increases in income taxes, as a result of timing differences, are offset in the income statement with corresponding credits or charges to the balance sheet accounts maintained for accumulating the net balances of deferred income taxes Timing differences arise as a result of reporting certain items of income and expense for book purposes in a different period than these items of income and expense are reported in the determination of taxable income for income tax purposes Accumulated deferred income taxes appear on the balance sheet under the captions Deferred Credits or Deferred Debts

a. Deferred Credits - A group of accounts carried on the liability side of the balance sheet representing the net balances arising from charges to income equivalent to the <u>reductions</u> in income taxes of the current and prior periods resulting from the use, for tax purposes, of deductions which, for book purposes, will not be fully reflected in the determination of book net income until subsequent periods Most commonly, they arise from normalizing the tax reductions resulting from the use of accelerated depreciation for tax purposes instead of the straight-line depreciation methods used for book purposes

b Deferred Debits - An account carried on the asset side of the balance sheet representing the net balance arising from credits to income equivalent to the increase in income taxes of the current and prior periods resulting from the use, for tax purposes, of items of income which, for book purposes, will not be fully reflected in the determination of book net income until subsequent periods

B Other taxes

1 Property Taxes

2. Gross Receipts Taxes

3 Sales Taxes

4 Franchise Fees

5 Business Taxes

6 Payroll Taxes

9 Cost of Service study

A. Functional assignment of costs

1 Generation Cost - Those capital and operating expenses incurred in the building a generating station that will transform other forms of energy into electric energy

2 Transmission Cost - Those capital and operating expenses incurred in the process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems

3 Distribution Cost - Those capital and operating expenses incurred in the process of distributing electric energy from convenient points on the transmission or bulk power system to the customer

4 Customer Cost - Those capital and operating expenses incurred by the utility in taking on another customer Usually includes such cost as services and metering as well as accounting and sales promotion expenses

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B. Classification of costs

1 Demand Related Cost - The capital and operating expenses incurred by the utility on behalf of an individual customer in providing sufficient capacity (a large enough generation, transmission and distribution system) to meet the maximum demand of that customer on an as needed basis Demand related cost is often used interchangeably with capacity cost They can also allow for a) voltage differences, b) distance between points of generation and consumption, c) power factor, and d) customer-density factor Demand related costs vary with the kilowatts (KW) of power demanded These costs are usually charged to customers as $ per KW

2. Energy Related Cost - The operating expenses incurred by a utility on behalf of an individual customer in providing that customer with a kilowatt hour (KWH) of electric energy Energy cost is used interchangeably with KWH cost. Energy costs vary directly with KWH usage and are primarily a fuel cost These costs are usually charged to customers as ¢ per KWH.

3. Customer Related Cost - The capital and operating expenses incurred by the utility on behalf of an individual customer that relate primarily to the number and size (usage) of customers and do not vary significantly with the amount of energy used These costs include such items as the service drop, metering, billing and frequently include a fraction of annual maintenance and capital costs of the low voltage distribution system. There are two methods for determining the amount of the low voltage distribution system to include in customer related costs

a. Minimum system approach - The fraction included is equal to the estimated annual costs of a hypothetical system of minimum capacity (smallest sizes of conductor, transformers, poles, etc that are adequate to maintain voltage) These costs are viewed as varying directly with the area of the distribution system

b Zero intercept approach - Regress cost against various sizes of equipment and use regression intercept to determine cost of a zero - sized system.

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C. Allocation of costs among classes of customers

1. Classes of customers

a. Residential - A customer, sales, and revenue classification covering electric energy supplied for residential (household) purposes. The classification of an individual customer's account when the use is both residential and commercial is based on principal use

b Commercial (Small Light and Power) - A customer, sales, and revenue classification covering energy supplied for commercial purposes, except energy supplied under special contracts or agreements or service classifications applicable only to municipalities, or division or agencies of Federal or state governments, or to railroads and railways

c Industrial (Large Light and Power) - A customer, sales, and revenue classification covering energy supplied for industrial purposes, except energy supplied under special contracts or agreements or service classifications applicable only to municipalities, or division or agencies of Federal or state governments, or to railroads and railways Most companies classify customers as Commercial or Industrial using the standard industrial classification or predominant KWH use as yardsticks, others will classify as industrial all customers whose demands or annual use exceeds some specified limit These limits are generally based on a utility's rate schedules

d Public Street and Highway Lighting - A customer, sales, and revenue classification covering electric energy supplied and services rendered for the purposes of lighting streets, highways, parks, and other public places, or for traffic or other signal service, for municipalities or other divisions or agencies of Federal or state governments

e. Other Public Authorities - A customer, sales, and revenue classification covering electric energy supplied to municipalities or divisions or agencies of Federal or state governments (as ultimate customers) under special contracts or agreements or service classifications applicable only to public authorities, except such items as are includable in the classifications public street and highway lighting, sales to railroads and railways, and sales for resale

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f Interdepartmental Sales - Kilowatt hour sales of electric energy to other departments (gas, steam, water, etc) and dollar value of such sales at tariff or other specified rates

g Railroads and Railways - A customer, sales, and revenue classification covering electric energy supplied to railroads and interurban and street railways for general railway use, including the propulsion of cars or locomotives, where such energy is supplied under separate and distinct rate schedules

h Sales for Resale - A customer, sales, and revenue classification covering electric energy supplied (except under interchange agreements) to other electric utilities or to public authorities for resale or distribution.

2 Demand related production and transmission costs

a. Straight CP - Make allocation based on the annual coincident peak, i e each customer class' contribution to the annual system peak

b 12 CP - Make allocation based on the average of the 12 monthly coincident peaks during the test year

c Average and excess - This method breaks capacity into two components The average portion of demand is allocated based on the KWH usage of the customer class The remaining, or excess, demand is allocated based on each class' contribution to coincident peak

3 Demand related distribution costs

a. Non-coincident peak demands for each customer class, i e the largest annual demand for the customer class during the test year This is frequently used for allocating substations and primary voltage distribution lines.

b The sum of individual peak demands for all members of a customer class, i e the largest annual demand for each customer during the test year This is frequently used for allocation of transformers and secondary voltage distribution lines

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4 Energy related costs are allocated based on each customer class' energy usage during the test year, measured in kilowatt hours

5 Customer related costs are allocated based on the number of customers in each class

10 Develop billing determinants

A. Customer charge - The number of customer months in each class during the test year.

B Energy charge - The total KWH of usage in each customer class during the test year

C Demand charge - The number of KW months of demand in each customer class during the test year

11 Calculation of rates - divide the demand, energy and customer costs allocated to each customer class by the corresponding billing determinant. This provides a starting point for rate design, which in reality is as much art as science

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DETERMINATION OF REVENUE REQUIREMENT

	OPERATION AND MAINTENANCE EXPENSES		
	PRODUCTION	$234,700,000	
	TRANSMISSION	$5,720,000	
	DISTRIBUTION	$19,060,000	
	CUSTOMER ACCOUNTS	$10,550,000	
	SALES EXPENSES	$490,000	
	ADMIN AND GENERAL	$25,200,000	
A	TOTAL O&M EXPENSES		$295,720,000
	NET ORIGINAL COST RATE BASE	$717,000,000	
	RATE OF RETURN	13 50%	
B	RETURN ON INVESTMENT		$96,795,000
C	DEPRECIATION		$41,980,000
	FEDERAL INCOME TAXES	$20,200,000	
	STATE INCOME TAXES	$6,720,000	
D	TOTAL INCOME TAXES		$26,920,000
E	TAXES OTHER THAN INCOME		$41,174,000
	REVENUE REQUIREMENT		$502,589,000

RATE BASE CALCULATION

PLANT IN SERVICE		
	PRODUCTION PLANT	700
	TRANSMISSION PLANT	115
	DISTRIBUTION PLANT	287
	TOTAL PLANT IN SERVICE	1102
CONSTRUCTION WORK IN PROGRESS		50
PLANT HELD FOR FUTURE USE		1
	TOTAL PLANT	1153
LESS:	ACCRUED DEPRECIATION	331
	DEFERRED INCOME TAX RESERVE	193
	CUSTOMER ADVANCES	2
PLUS:	MATERIALS AND SUPPLIES	53
	CASH WORKING CAPITAL	37
TOTAL RATE BASE		717

CWIP AND AFUDC

CASE 1. RETURN EARNED ON CWIP IN RATE BASE.

CASE 2. AFUDC IN INCOME WITH NO RETURN ON CWIP IN RATE BASE.

	CASE 1	CASE 2
PLANT IN SERVICE	800	800
CWIP	200	200
RATE BASE	1000	1000
ALLOWED ROR	8%	8%
NET OPERATING INCOME	80	64
AFUDC	0	16
INCOME BEFORE INTEREST CHARGES	80	80

CWIP IN RATE BASE WITH NO AFUDC.

YEAR	1	2	3	4
PLANT IN SERVICE	800	800	800	1100
CWIP	0	200	300	0
RATE BASE	900	1000	1100	1100
ALLOWED ROR	8%	8%	8%	8%
NET OPERATING INCOME	72	80	88	88
AFUDC	0	0	0	0
INCOME BEFORE INTEREST CHARGES	72	80	88	88

CWIP IN RATE BASE WITH AFUDC IN ALLOWED INCOME

YEAR	1	2	3	4
PLANT IN SERVICE	800	800	800	1151
CWIP	100	208	325	0
RATE BASE	900	1008	1125	1151
ALLOWED ROR	8%	8%	8%	8%
NET OPERATING INCOME	64	64	64	92
AFUDC	8	17	26	0
INCOME BEFORE INTEREST CHARGES	72	81	90	92

COST OF MONEY EXAMPLE

CAPITALIZATION	CAPITALIZATION RATIOS	INTERST RATE	ROR TOTAL CAPITAL
COMMON STOCK	45%	12%	5.40%
PREFERRED STOCK	5%	8%	0.40%
DEBT	50%	7%	3.50%
	100%		9.30%

DISCOUNTED CASH FLOW

$30 00	PRICE OF THE STOCK
$2.40	DIVIDEND PER SHARE
4 00%	EXPECTED ANNUAL DIVIDEND GROWTH RATE
12 00%	RETURN ON EQUITY CALCULATED AS ((2 40/30)+ 04)

PREFFERED STOCK	EMBEDDED COST OF MONEY	AMOUNT OUTSTANDING
7 2% SERIES	7 20%	$12,500,000
8 5% SERIES	8 50%	$20,000,000
	8 00%	$32,500,000

FIRST MORTGAGE BONDS	EMBEDDED COST OF MONEY	AMOUNT OUTSTANDING
SERIES DUE 8/1/98	8 00%	$110,000,000
SERIES DUE 12/1/09	6 00%	$75,000,000
SERIES DUE 3/1/18	6 75%	$140,000,000
	7 00%	$325,000,000

TAX GROSS UP

	CAP RATIOS	INTEREST RATE	ROR ON TOTAL CAPITAL	TAX GROSS UP	GROSSED UP ROR
COMMON	45%	12%	5.40%	20.69%	9.31%
PREFERRED	5%	8%	0.40%	13.79%	0.69%
DEBT	50%	7%	3.50%	7.00%	3.50%
	100%		9.30%		13.50%

TAX RATE 42%

$$\frac{.12}{(1 \quad 0.42)} = .2069 \qquad \frac{.08}{(1 - 0.42)} = .1379$$

Straight Line Depreciation Example

Cost. $100,000
Salvage. 20,000
Life. . . . . 20 years

$$d = \frac{\$100{,}000 - \$20{,}000}{20 \text{ years}}$$

$$= \frac{\$80{,}000}{20 \text{ years}}$$

$$= \$4{,}000/\text{year}$$

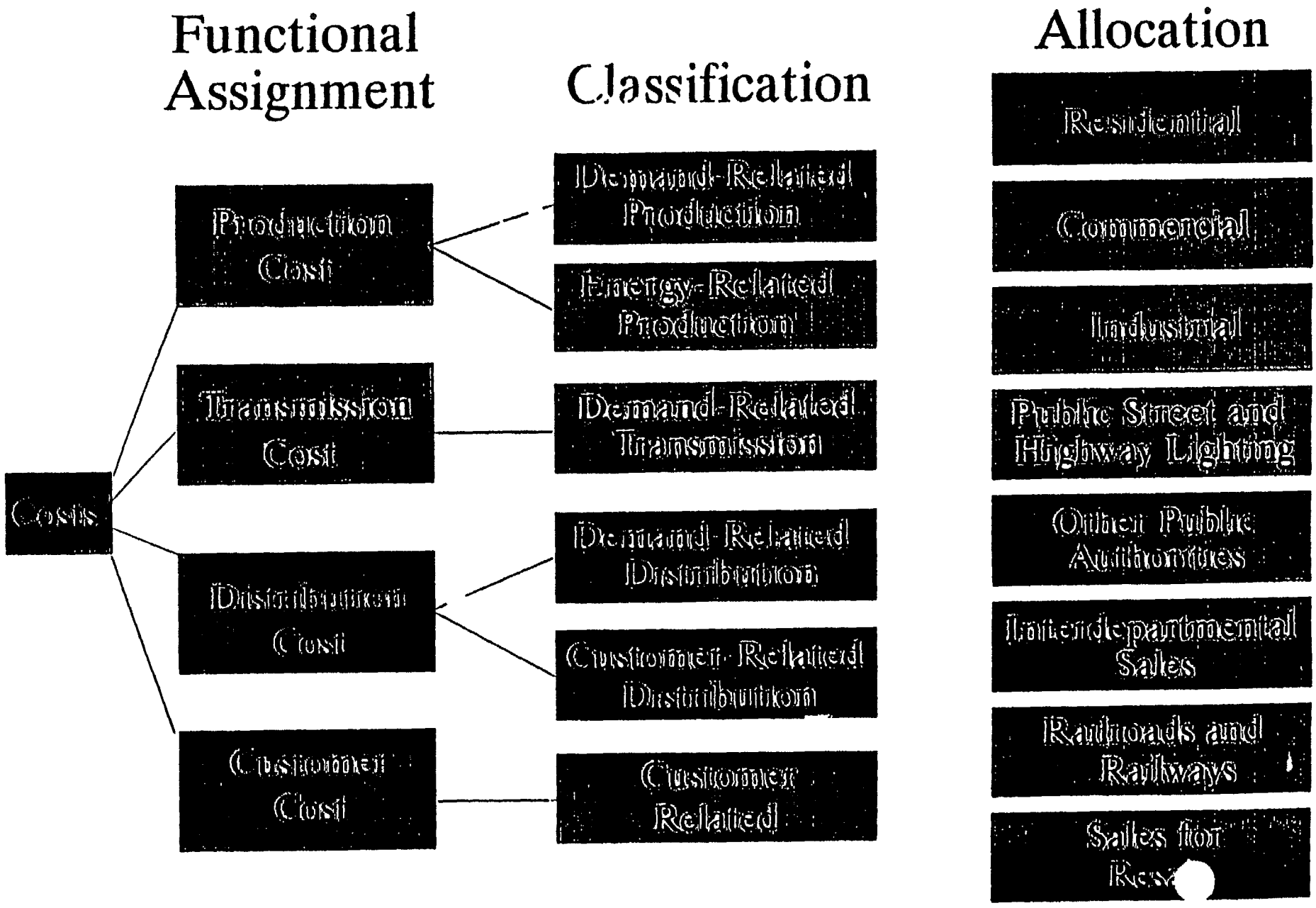
Year	Depreciation Per Year	Accrued Depreciation
1	$4,000	$4,000
2	$4,000	$8,000
3	$4,000	$12,000
4	$4,000	$16,000
5	$4,000	$20,000
6	$4,000	$24,000
7	$4,000	$28,000
8	$4,000	$32,000
9	$4,000	$36,000
10	$4,000	$40,000
11	$4,000	$44,000
12	$4,000	$48,000
13	$4,000	$52,000
14	$4,000	$56,000
15	$4,000	$60,000
16	$4,000	$64,000
17	$4,000	$68,000
18	$4,000	$72,000
19	$4,000	$76,000
20	$4,000	$80,000
		+ $20,000 Salvage
	Total Recovered	$100,000

The accrued depreciation is deducted from original cost rate base to determine net rate base.

ACCELERATED DEPRECIATION

- Declining Balance
- Double Declining Balance
- Sum-of-the Year's Digits
- Accelerated Cost Recovery System (ACRS)

Cost of Service Study



RESIDENTIAL CLASS

CUSTOMER CHARGE	$12.75
DEMAND CHARGE	$16.50
KWH CHARGE	$0.018

KWH USAGE	KW USAGE	TOTAL BILL
100	1	$31.05
500	2	$54.75
1000	3	$80.25
1500	4	$105.75

RESIDENTIAL CLASS

CUSTOMER CHARGE	$5.00
KWH CHARGE	$0.073

KWH USAGE	TOTAL BILL
100	$12.342
500	$41.710
1000	$78.420
1500	$115.130

RESIDENTIAL CLASS

COST ALLOCATION

DEMAND	$94,665,780
ENERGY	$37,694,250
CUSTOMER	$35,190,000
TOTAL	$167,550,030

BILLING DETERMINANTS

KW-MONTHS	5,737,320
KWH	2,094,125,000
CUSTOMER MONTHS	2,760,000

RATES

DEMAND ($/KW-MONTH)	$16.50
ENERGY ($/KWH)	$0.018
CUSTOMER CHARGE	$12.75
AVERAGE USAGE	758.7

DEMAND RELATED PRODUCTION AND TRANSMISSION

	COINCIDENT PEAK	AVERAGE KW
RESIDENTIAL	600	400
COMMERCIAL	300	200
INDUSTRIAL	100	100
	1000	700

ALLOCATIONS BASED ON CP

RESIDENTIAL	60%
COMMERCIAL	30%
INDUSTRIAL	10%

ALLOCATIONS BASED ON AVERAGE AND EXCESS

70% OF THE PLANT WOULD BE ALLOCATED BASED ON CLASS KWH USAGE.

30% OF THE PLANT WOULD BE ALLOCATED BASED ON CP

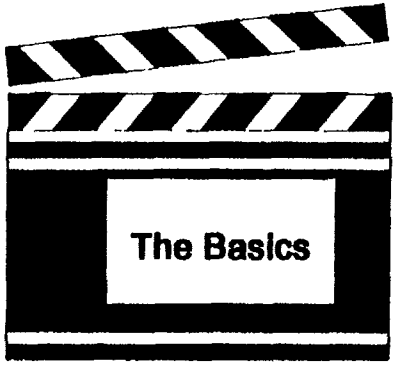
Creating Synergies Between Least-Cost Planning, Competition and Regulation

NARUC Annual Regulatory Studies Program

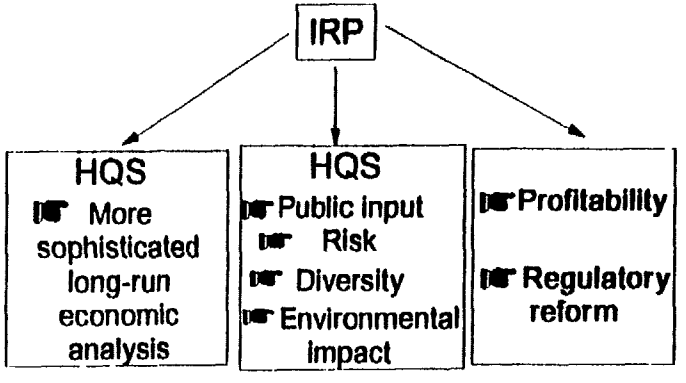
August 3, 1995

David Moskovitz
The Regulatory Assistance Project
177 Water Street Gardiner Maine 04345 2149
Phone (207) 582 1135 Fax (207) 582 1176

Part A



What is IRP?



All Regulation is Incentive Regulation

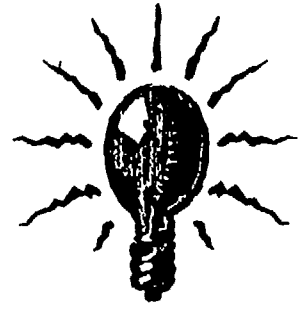
- The incentives built into the existing system are large and directly at odds with LCP
- A one percent (1%) change in a utility's sales results in a change to ROE of about 100 basis points
- LCP won't happen by wishing it.
- You need to remove the disincentives

Big Picture

- *NARUC RESOLUTION*
  The successful implementation of a utility's least-cost plan should be its most profitable course of action
  Restated
- The regulatory system should be designed and operated to harmonize the interests of the utility, its customers and sound public policy

The Current System

- ' Wh sold adds to profits
- Every kWh saved cuts into profits
- The sole incentive ngage in LCP is fear of regulators



It's Incremental Profits

- Is a two-cent DSM option less attractive to the utility than a three-cent supply option?
- Does it hurt the utility when a customer invests in energy iciency on the advice of the utility or in response to price signals?
- Does the sale of power for 5 cents/kWh which costs 6 cents to produce add to utility profits?

IF ANY ANSWER IS "YES" LCP WILL BE DIFFICULT

Back to the Basics

- The current system sets prices -- nothing else!
- The rate case
  - Step 1 REV REQ = EXP + (RR * RB)
  - Step 2 PRICES = REV REQ / SALES
- END OF CASE

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Basics: Part 2

- ACTUAL REV = PRICE * SALES
- ACTUAL COSTS = ?

- The theory is that once prices are set, costs, revenues and sales all grow in lockstep

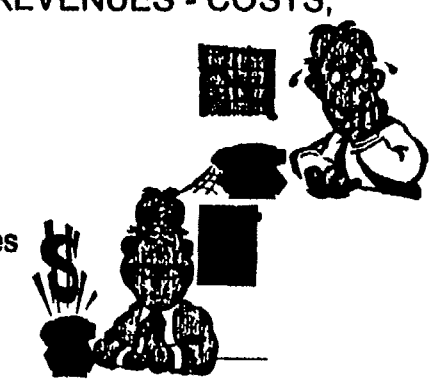
- The theory is interesting but it bears no resemblance to reality

Basics: Part 3

- PROFITS = ACTUAL REV - ACTUAL COSTS
- What happens if ACTUAL REV increases with sales but costs don't?
- The result is -- increased sales lead to increased profits It is that simple
- Want proof? What's the biggest rate case issue in a future-test-year jurisdiction?

Three Ways to Profit

- PROFITS = REVENUES - COSTS, so
  - Cut costs
  - Raise rates
  - Increase sales



Remove Disincentives

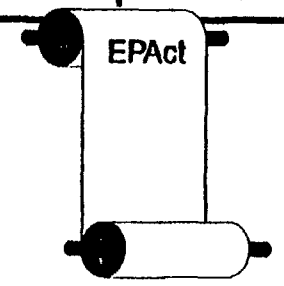
- There are only two options
  - Decouple profits from sales
  - Lost revenue adjustments

- **They are very different!**

Decoupling vs. Lost Revenues

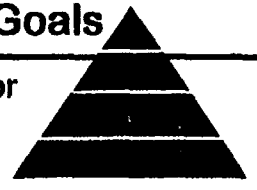
- DECOUPLING
  - Removes sales incentive and all DSM disincentives
  - Addresses rate design
    - all DSM programs
    - efficiency standards
    - not dependent on M&E
  - Can be relatively simple to administer and difficult to game
  - Eliminates load forecast gaming, limits recovery to actual savings
- LOST REVENUES
  - Does not remove sales incentive or some DSM disincentives
  - Entirely dependent on after the-fact M&E (lots of $) and raises host of new measurement issues, such as offsets from sales
  - Misses rate design
    - some DSM programs
    - customer DSM
  - Dilemma of increased rigor and state-of the art M&E makes DSM appear to be a high risk path to utilities

Decoupling in Perspective



- Energy Policy Act
- Clean Air Act
- Traditional regulation is decoupled - we have unintentionally and unknowingly departed from traditional regulation
  - Long run
  - Short run

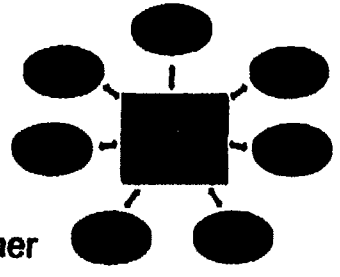
Decoupling Goals



- To make utility earnings or profits independent of sales while continuing to allow utilities a reasonable opportunity to recover costs
- To reconcile utility financial interests with least-cost planning
- To ensure that the utility's successful implementation of an LCP is its most profitable course of action

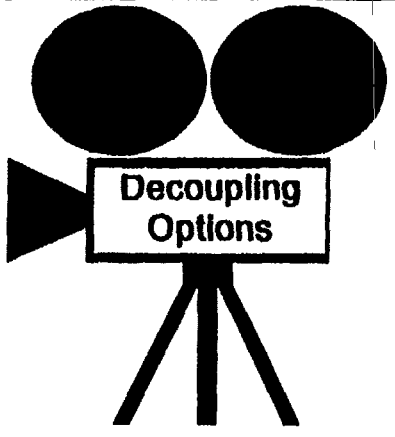
Decoupling Options

- × DSM incentives
- × Rate design
- × Fuel clause reform



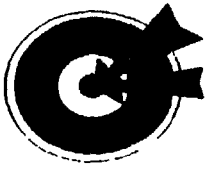
- ✓ ERAM
- ✓ Revenue per customer
- ✓ Statistical recoupling

Part B



ERAM

- Adopted in California and New York
- Proposed in Oregon
- Applicable in states using future-test-year ratemaking
- Requires annual rate or "attrition" cases to determine rate year non-fuel revenues



ERAM (page 2)

- FTY used to establish the non-fuel revenue requirement (NFRR)
- NFRR is used to set prices
- At the end of the rate year, the NFRR from the rate case is compared to the actual non-fuel revenue collected from customers
- Differences are collected or returned to customers over the next year
- Both California and New York have adopted three-year rate case cycles
- The NFRR for years 2 and 3 are set in an "attrition" case

ERAM Characteristics

- Decouples
- Shifts weather risk and economic risks
- Adds some stability to utility revenues and customer bills
- Removes rate design risk from utility

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ERAM - Advantages and Disadvantages

- Advantages
  - Builds on some existing rate-making practices
  - Allows for rate design changes
- Disadvantages
  - Requires future test-year rate-making
  - Requires annual rate cases of some sort

Revenue Per Customer

- Adopted in Maine and Washington, proposed in FL, DC, MT, CA
- Close relationship to existing practices
- Current system assumes non-fuel costs grow in proportion to sales
- Revenue per customer assumes that non-fuel costs grow in proportion to customer growth

RPC Mechanics

- Can be used in states with either historic- or future-test-year
- Allowed test-year (historic or future) non-fuel revenue requirement is divided by test-year customer count to produce "allowed revenue per customer"
- There is no change to the way prices are set

RPC Mechanics (continued)

- At the end of the year, actual revenue collected on a kWh basis is compared to allowed revenue
- Differences, plus or minus, are recovered over the next 12 months

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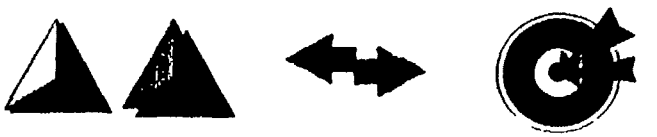
RPC Characteristics

- Decouples
- Shifts weather risk but only part of business cycle risk
- Allows innovative rate design without risk to utility
- Requires annual rate cases of some sort

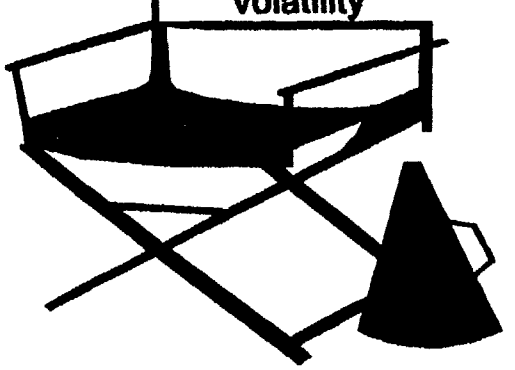
RPC vs. ERAM

- Can be used with historic- or future-test-year rate-making
- Does not require annual rate cases
- Shifts focus to revenue per customer, i e average customer bills
- Difficult to game



Part C

Risk and Price Volatility

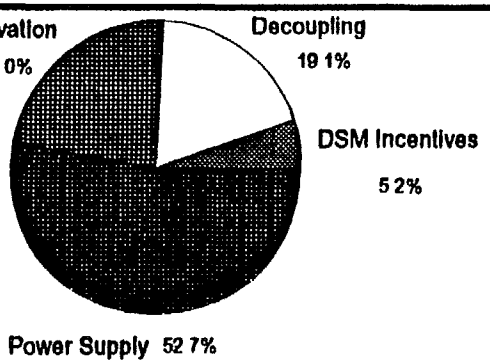


Let There be no Mistake!

- Decoupling CAN shift risks from utilities to customers

- Volatility of decoupling adjustments exactly equals earnings volatility

Washington PRAM Reconciliation

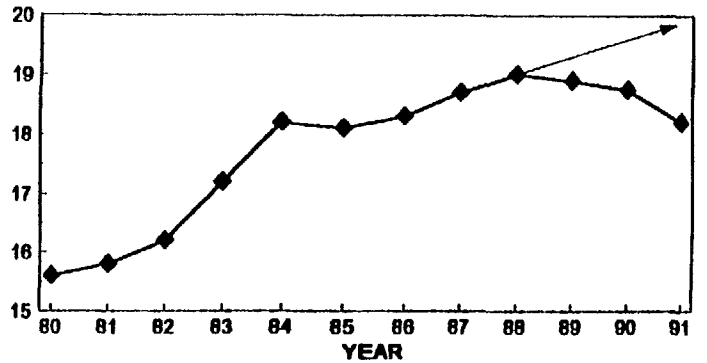


% of Reconciled $

WTU Docket No UE 920630 9/24/92

Central Maine Power

Average Use Excluding Lighting & Resale

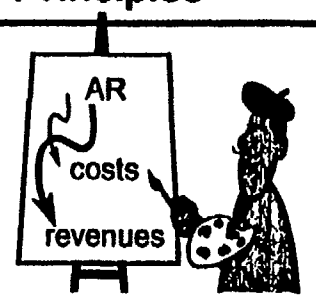


Price Impacts

- When properly designed, a revenue reconciliation mechanism will produce price increases as often as price decreases
- The average price change is zero but it's the maximum swings that matter

Design Principles

- Option 1 - "Allowed Revenues" track actual costs
- Option 2 - "Allowed Revenues" track actual revenues



Note Price changes result from differences between "allowed" and actual revenues

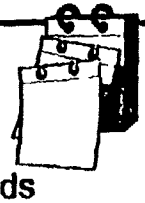
Guiding Principles

- Assess extent and origin of risk
- Assess value to customers of taking on risk
- Consider options to reduce volatility
  - Decoupling by customer class
  - Averaging rate changes
  - Weather Adjustments
  - Economy adjustments
  - Statistical recoupling
  - Cap on amount of deferral
- Balance extent of price volatility against cost reduction and simplicity

Risk Shifting: At what cost?

- Shifting risk isn't bad per se
- Has the party with the risk been compensated?
- If utility has risk, customers compensate them in the form of higher COE

Averaging Rate Changes



- Volatility in accruals are likely to average out over time
- Extending the recovery period tends to dampen fluctuations in rates
- EITF (Emerging Issues Task Force) requires that accruals be recovered in 24 months for accruals to be recognized as income

Origins of Risk

- What risks were created by "old fashioned" rate designs?
- How are those risks different now?

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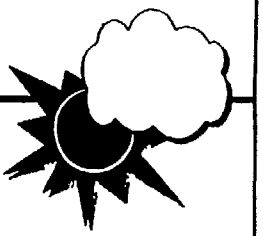
Weather and Business Cycle Risks

- Extent of risk varies among utilities
- Significant risk shifts are to be reflected in price of stock and cost of capital
- Can reduce (in principle, eliminate) risk shifts
- Conservative estimates of the relationship between weather, or the economy, and sales produce a sharing of risk

Weather Risk



STEP 1 Where should it be?
- Maine?
- Washington?

STEP 2 How large is it? FPC data

STEP 3 Consider multi-year averaging

STEP 4 Is there an established weather normalization process?

STEP 5 Construct a simple adjustment with the goal of controlling price volatility

Examples

- Montana Power Company
- Oregon
  - Pacific Power
  - Portland General

Economic Risk

STEP 1 Who bears it now? What are the sources? Sales volume? Mix? Who should bear it?

STEP 2 How large is it?

STEP 3 What will multi-year averaging accomplish? -- 2-year Rule?

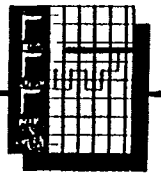
STEP 4 Consider customer count definition

Economic Risk (cont'd.)

STEP 5 Consider revenue reconciliation by customer class

STEP 6 Consider a simple adjustment with the goal of controlling price volatility

Caps on Accruals



- For example, the utility may not accrue more than $x per year
- When cap is active, the incentive to sell more and conserve less returns
- Makes utility planning and consistent delivery difficult
- Caps based on earned return troublesome
  - Utilities probably will respond by increasing spending
  - Higher spending levels may be reflected in test year of upcoming rate case

Statistical Recoupling

- A more comprehensive approach to minimize price volatility
- Can be used to establish "B" factor
- Nature of its use makes gaming difficult

Lessons Learned

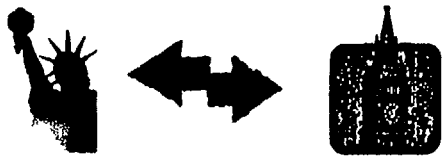
- Assess extent and sources of volatility
- Assess customers value of risk
- Consider options to reduce volatility
  - Decoupling by customer class
  - Averaging rate changes
  - Weather Adjustments
  - Economy adjustments
  - Cap on amount of deferral
  - Statistical recoupling

- Balance extent of price volatility against cost reduction and simplicity

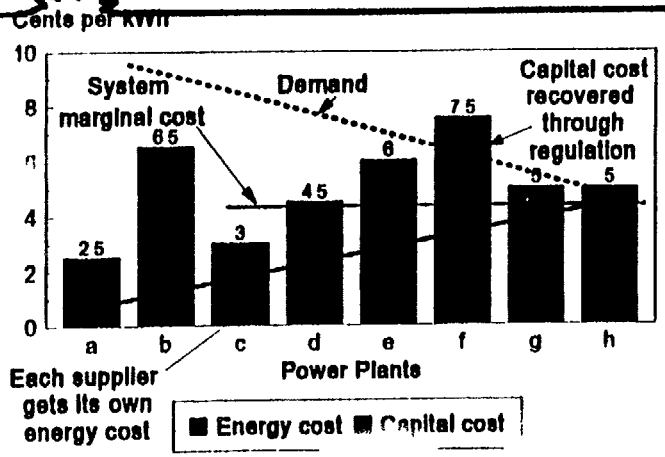
Part D

Cost Versus Value

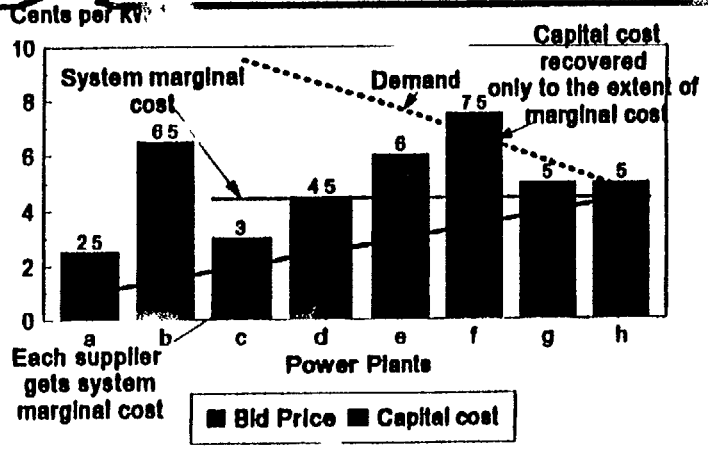
- Market prices, not cost, are the sole means of cost recovery
  - Market prices bear no clear relationship to costs
- Comparing US and UK style power pools illustrate the key difference



Cost Based (US) POOL



Market Based (UK) POOL



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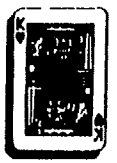
Some Definitions

- Wholesale Competition
  - Increase competitiveness of Generation Market
  - Use PBR to improve Utility Incentives
  - Maintain franchise & obligation to serve
- Retail Competition
  - Competitive Generation
  - Eliminate franchise & obligation to serve
  - PBR for wires portion of business

Requirements for Effective Competition

- No buyer or seller influences price
- Arm's length deals
- Equal access to transmission at non-discriminatory prices
- May need market mechanisms to facilitate trading
- All costs internalized

Making Markets Work



- **Market power**
- **Self dealing**

Require careful thought as to

- What industry structure
- What kind of regulation

Market Power

- How concentrated is the market?
- How large is the largest player?
- How large does a player need to be to be a price setter?

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Self Dealir

- Vertically integrated utilities create ·s problems for competition
  - Buy over-priced generation from generation arm, pass costs to monopoly customers
  - Restrict supply by restricting transmission access and refusing to buy from competitors
  - DSM reduces demand & market price of ration
  - Discourage entry of competitors

Steps Along The Way

No competition → Fully co ive

Pre IRP → IRP → Competitive bidding → PBR → Deregulated generation

Retail Competition Defined

- Existing utility service is unbundled
  - Customer buys power from alternate supplier
  - Customer buys delivery and related services from old supplier
- Customers have direct access to wholesale generation market

Retail Issues

- Most of the wholesale issues need to be resolved
- New issues or concerns must be considered
  - Stranded costs
  - Planning/obligation to serve

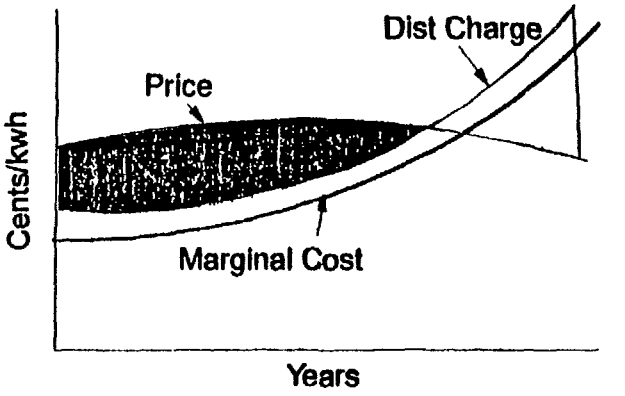
How Defined

Retail rate costs minus market value of power minus wheeling charges

Don't forget -

- Everything has a time and forecasted element
- Future costs not yet in retail rates e g decommissioning, deferred costs, rate agreements
- Salvage value e g valuable sites

Stranded Cost Fish



Planning

Wholesale

- Obligation to serve means utility has obligation to plan, build, and buy
- Customer obligation to pay prudent costs

Retail

- Utility has obligation to connect
- Customer obligations to pay whatever they agree to

Financial Environment

- New resources will be financed on the basis of contracts
  - With utility, but backed up by customer contracts or enforceable exit/entry conditions
  - With customers
- Spot market

Winners and Losers

- Likely Winners
  - High fuel/low capital
  - Existing units

- Possible Losers
  - Baseload
  - DSM
  - Renewables
  - R&D
  - Other capital-intensive stuff

Opportunities

- Divested generation is probably good
- Open access transmission
- Attributes of renewables are attractive to customers
- Funds needed for S O D are small and have broad public support

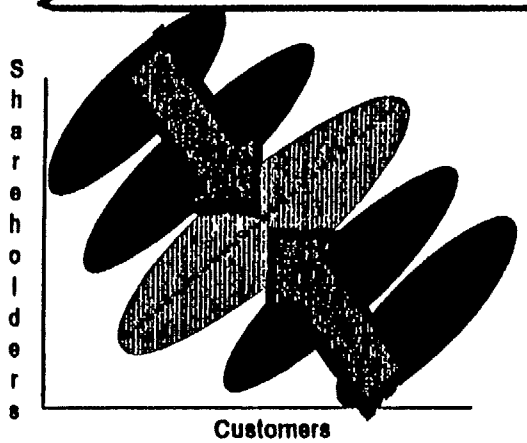
Targeted Competitive Options

- NFFO with bidding
- Internalize externalities

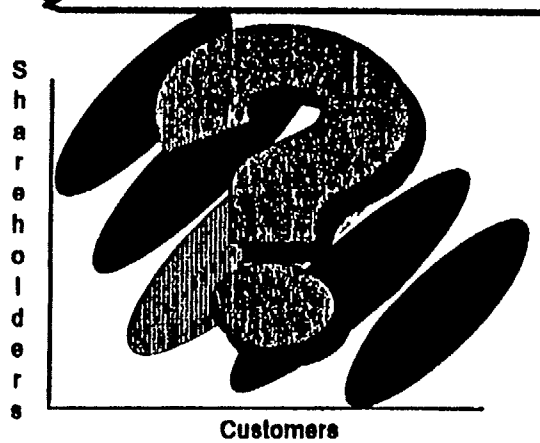
Customer Choice

- Market can be very large
  - 2 5% now compared to 5% - 15%
- Two ways to tap market
  - Retail access
  - Green pricing

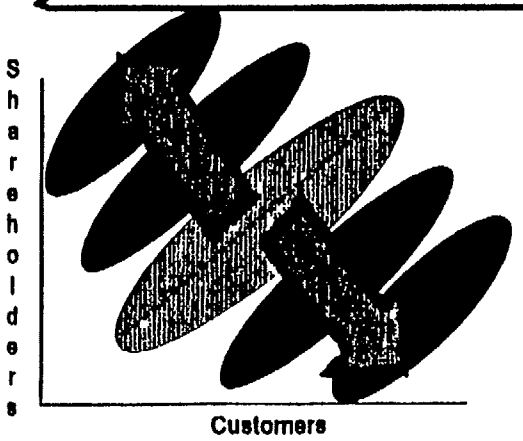
History



The Future



The Transition



Regulatory Options

- Three options when utility and public interest diverge
  1. Wish the conflict away and do nothing
  2. Recognize conflict and increase regulatory vigilance accordingly
  3. Recognize conflict and adopt simple, understandable, publicly acceptable replacements for regulatory/public process
     - portfolio standards
     - set asides

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Session 9

COSTING AND RATEMAKING

Johannes M Bauer
Michigan State University

Prepared for presentation at the
Annual Regulatory Studies Program at Michigan State University
East Lansing, Michigan, August 1, 1995

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TOPICS COVERED

- Funcions of Pricing
- Basic Approaches to Pricing
- Basic Rate Designs
- Market-compatible Rate Design

FUNCTIONS OF PRICING

1. **Capital attraction**

2. **Efficiency incentive** (1) [illegible] EFFICIENCY
   (4) DYNAMIC [illegible] (INNOVATION OF [illegible] BY [illegible])
   (5) ALLOCATIVE EFFICIENCY ⇒ [illegible] TO SOCIAL BENEFITS

3. **Consumer rationing**

4. **Compensatory income transfer**

BASIC APPROACHES TO PRICING

1. **Principal steps in traditional ratemaking**

   a Determination of revenue requirements

   b Allocation of revenue requirements to different customer classes

   c Translation into rates

2. **Fully allocated cost pricing (fully distributed cost-of-service pricing or average cost pricing)**

   a The basis for determining the revenue contribution of each customer or user group are fully allocated current and embedded costs

   - Costs are segregated between those that are directly assignable and those that are overhead, common, or joint costs
   - The non-assignable costs have to be allocated according to some convention, frequently on the basis of time if use and volume of use

BASIC APPROACHES TO PRICING (cont'd)

b Developed as a constraint on the abuses of value-of-service pricing.

c. Advantages of fully allocated cost pricing:

- Total allocation reconcilable with revenue requirement
- Provides an estimate of cost traceability and cost causation

d Disadvantages of fully allocated cost pricing.

- Too little attention to demand criteria
- Based on historical usage data rather than on forward looking criteria.
- Difficulty of introducing new services
- No agreement on methods for allocating common and joint costs.
- Embedded costs $\neq$ economic costs (opportunity costs) of service
- Vulnerable to umbrella pricing.

BASIC APPROACHES TO I ING (cont'd)

3. **Demand-based pricing (value-of-service pricing)**

   a Prices are demand oriented Revenue requirements are assigned according the relevant demand characteristics of customer of user groups No efforts are being made to allocate accounting or economic costs to classes of customers or user groups.

   b. Advantages of demand-based pricing·

   - Recognizes demand characteristics of different markets
   - Gives management flexibility to adjust to changing market conditions

   c Disadvantages of demand-based pricing·

   - Cost criteria by service are ignored, resulting in a potential for abusive pricing practices (e g , peak stimulation)
   - Arbitrary if all demand functions are highly inelastic
   - Price experimentation with lower rates limited to markets perceived to be elastic.

BASIC APPROACHES TO PRICING (cont'd)

- If regulatory constraint over revenue requirement is removed, then the potential for monopolistic pricing is greatly enhanced.

4. Marginal or incremental cost pricing

a Attempts to equate the demand for service (the willingness to pay) with the marginal (or incremental) cost of providing that service Thus, it attempts to incorporate demand as well as supply-side information

b Applied to peak and off-peak pricing and the pricing of individual services Pricing of former is based on incremental cost of meeting peak and off-peak demand Pricing for latter is based on incremental cost of adding or subtracting output to meet the demand for a specific service

c. Advantages of marginal cost pricing·

- Attempts to correct the major deficiencies of both demand-based (i e , ignoring costs) and fully distributed cost (i e., ignoring current demand

BASIC APPROACHES TO PRICING (cont'd)

and attempting to allocate embedded costs) pricing

- Forward looking If successful, bases the cost of expansion on economic instead of accounting costs.

- Disadvantages of marginal cost pricing:

- Revenue reconciliation problem How can sales revenues based on prices reflecting marginal cost be reconciled with the total revenue requirement reflecting current and embedded costs.

  Deficits or monopoly profits may result.

- Problem especially visible in industries with high economies of scale (e g , natural monopolies in the decreasing part of the LRAC)

  Revenues based on MC < AC fall short of production cost

LRAC

BASIC APPROACHES TO PRICING (cont'd)

Possible solution is pricing subject to a minimal revenue constraint (i e., the firm is allowed to increase its prices in a way to recover its total costs)

- Marginal costs in practice may be complicated to determine

  Indeterminate and arbitrary nature of demand and long-run incremental cost estimates
  Potential for abuses Shifting overheads to inelastic markets can produce the same results although ostensibly carried out in a marginal cost format

BASIC RATE DESIGNS

1. Uniform versus non-uniform tariffs

a A rate schedule is called *uniform* when total outlay in a market is simply proportional to the amount of a service purchased

- Different rates are possible for different groups of consumers
- Examples are linear rates, peak-load prices, or Ramsey prices (see below)

b A rate schedule is called *non-uniform* if a consumer's outlay does not simply rise proportionately with the amounts purchased

- Non-uniform prices allow for price differentiation within one market, for example through quantity discounts and quantity premia

- Examples are flat rates, declining block rates or inverted block rates (multi-part tariffs).

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BASIC RATE DESIGNS (cont'd)

2. Declining block rates

a Example (tariff charged by Commonwealth Edison)

Monthly fixed charge	120 00¢
Usage charge 0-100 kWh	4.18¢
Usage charge > 100kWh	3 14¢
Price/kWh for 100kWh	5.38¢
Price/kWh for 200kWh	4.26¢
Price/kWh for 500kWh	3 58¢

b Rationale

- Declining average price promotional and this is assumed to correspond with the declining average cost of production
- Allows recovery of non-assignable costs through fixed charge and part of the usage sensitive charge

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BASIC RATE DESIGNS (cont'd)

- Pareto-improvement since everyone will be better off than if all output were supplied at single price.
- Seen as "reasonable" form of price discrimination

c Problems

- If marginal cost is rising or if there are significant social costs involved in the provision of the service, declining block rate will have perverse effects on efficiency.
- In its simplest form no recognition of peak/off-peak usage This benefits peak users Off-peak users subsidize overexpansion of plant and capacity
- Equity issues. Steep declining blocks burden small users who do not expand consumption

BASIC RATE DESIGNS (cont'd)

3. Peak pricing

a Examples

- Peak pricing can be based on either marginal (incremental) of average (fully allocated) costs.
- Peak/off-peak differentials can be based on 24-hour or 12-month periods or some combination of periods
- High peak prices (reflecting the costs of meeting the peak) and low off-peak rates (reflecting low off-peak costs)
- Time-of-day rates in electricity or telephone service

b Rationale

- Sends proper price signals to consumers
- Conducive to improved load and capacity factors while constraining new investment

2-6

BASIC RATE DESIGNS (cont'd)

c. Problems

- Load shifting
  - Contradictory empirical evidence
  - Load shifting versus depression of entire demand
- Impact of metering costs on net saving in additional investment
- Political sustainability
- Implementation problems if
  - Marginal costs decline rapidly
  - Ramsey pricing is employed and (1) marginal cost is rising; (2) peak demand is inelastic, and (3) off-peak demand is elastic
- Conflict between peak pricing and direct load management
- Effect on environmental protection and conservation

BASIC RATE DESIGNS (cont'd)

4. Inverted block rates

a Rate increases with amount consumed

b Rationale

- Promoted by some consumer groups and conservationists Premised on the belief that a promotion of usage is harmful and that the real pattern of private and social costs rises with greater output

c Problems

- May not reflect incremental cost of service.
- Potential cross-subsidization of small users by large users
- Potential strategy for firm reluctant to increase capacity Could enhance opportunities for monopoly pricing.

5. Lifeline rates

a Can be seen as one variant of inverted block rates

b Rationale

- Corrects for the regressive effects of declining block rates
- Assures basic service to low income customers
- Less dependent on legislative discretion
- More efficient than income support programs (welfare payments, energy stamps, etc)

c Problems

- Abuse by affluent consumers
- Cross subsidization
- Effectiveness and efficiency as method for assuring service
- Can income-targeted lifeline rates be developed?
- Establishment of consumption ceilings?

MARKET-COMPATIBLE RATES

1. Price discrimination

a Price discrimination exists when the same product or service is sold at different prices to different buyers. The cost of production is either the same, or it differs but not as much as the difference in the charged price. Price discrimination also exists if buyers are charged different prices for different units of service such as in the case of decreasing block rates

b In an industry with decreasing marginal costs, price discrimination can be a solution to overcome the revenue reconciliation problem and to induce the firm to produce first-best outputs

c. *Primary* price discrimination (also called perfect price discrimination) exists, if the monopolist charges for each unit of output exactly what the consumer is willing to pay for it *Second degree* price discrimination exists if the monopolist can negotiate more than two different prices, and *third degree* price discrimination exists if the monopolist can negotiate two different prices.

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MARKET-COMPATIBLE RATES (cc

d In contrast to average cost pricing, primary price discrimination induces the regulated firm to achieve the first-best solution.

e Even if technically feasible, primary price discrimination may have several disadvantages.

- Charging different consumers different prices may seriously violate equity and fairness considerations of rate-making (eve n if some forms of price discrimination are allowed in ratemaking, such as differences between residential and business customers)
- Primary price discrimination results in high profits for the regulated firms which receives total social surplus. It could be imagined to tax away a part of those profits and to redistribute them to the customers of the firm. This would still induce the firm to produce first-best outcomes However, such a solution leads to new problems such as the question of whether regulators have the authority to tax and how the tax funds can and should be distributed to customers.

2. Ramsey-Boiteux-Prices

a Most public utilities produce more than one good or service and/or sell their output in more than one market with a different price in each market Examples are power utilities that sell both natural gas and electricity or electric utilities selling to residential and different types of business customers

b If marginal cost pricing results in losses, prices have to be increased above marginal costs until the firm breaks even. If the firm only sells one good or service, the second-best price is the average cost price When more than one good is sold or one good is sold in more than one market, the second-best outcome is not immediately obvious Many price combinations exist that let the firm break even For example, the price of gas could be increased until the loss is absorbed, the price of electricity could be increased until the losses are absorbed or any combination of price increases in the two markets could be chosen

MARKET-COMPATIBLE RATES (cont'd)

c. If the basic premises of welfare economics are accepted, the "best price combination is the one that minimizes the loss of social surplus as compared to the first-best solution of marginal cost pricing. Such a second-best solution is identified by *Ramsey-Boiteux Prices* (frequently and identified as Ramsey prices). Of all possible price combinations for a multiproduct firm, Ramsey-Boiteux prices provide the greatest total surplus while allowing the firm to break even

d. Ramsey-Boiteux prices are characterized by the following features

- The output of each service is reduced by the same proportion (approximately the same amount if demand is not linear) relative to the outputs that would be produced when prices are set at marginal cost.
- The amount by which price exceeds marginal cost, expressed as a percentage of price, is greater for goods with less elastic demand If the demand for the services is independent (i e., the cross-elasticity is zero), the percent increase of prices over marginal cost is proportional to the inverse price elasticity of demand (inverse elasticity rule). If the

MARKET-COMPATIBLE RATES (cont'd)

demand for the services is not independent, the cross-elasticities have to be taken into account. In this latter case, if a price increase in a market with a low price elasticity has spill-over effects into other markets, the resulting price increase is lower than in the independent services case

Markup in each market $= (P_i - MC_i)/P_i = \lambda/\epsilon_i$ [1]

This is equivalent to the following condition.

$[(P_i - MC_i)/P_i]\ \epsilon_i = \lambda$ [2]

i e the markup in each market times the price elasticity of demand should be equal and increased by a factor λ until the deficit of the firm is eliminated

MARKET-COMPATIBLE RATES (cont'd)

e. A disadvantage of Ramsey-Boiteux prices is that consumers with a low price elasticity of demand bear a heavier burden than consumers with a high price elasticity of demand. If this is caused by the lack of substitutes for those customers (captive customers), or the character of the service as a necessity, this may be against principles of just, reasonable, and fair ratemaking

f. The mark-up rule of Ramsey-Boiteux prices may symmetrically be applied and lead to *mark-downs* if a regulated firm produces under conditions of LRIC > LRAC and, hence, realizes a super-normal profit. In this case, prices in elastic markets will have to be marked down relatively less than prices in inelastic markets.

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4. Multi-part tariffs

a Multi-part tariffs are tariffs with several billing components such decreasing or increasing block rates, or tariffs that consist of an access and a usage component

b Appropriately designed multi-part tariffs can help emulate the functions of competitive markets and achieve first-best results in terms of efficiency Moreover, they may significantly outperform Ramsey-Boiteux prices from an efficiency point of view.

c Example· Access/Usage Tariffs

- If demand for access to a service (e g., to the telephone network) is (relatively) fixed, a regulated firm may produce the first-best output at marginal cost if it can recover the fixed cost of production through an *access charge* and a *usage charge* that equals the marginal cost of producing the service (This result was first proposed by Ronald Coase in 1946) Economically, the access charge is equivalent to a tax.

MARKET-COMPATIBLE RATES (cont'd)

resulting in a subsidy to the firm. The consumer decision at the margin is not affected

For example, if a phone company faces fixed costs of $2 million and a constant marginal cost of 5 cents to provide a call on the network, and the number of customers is 200,000, the Coase result would be to charge an access fee of $10 and a usage charge of 5 cents per call.

- If the demand for access is sensitive to price, an access fee cannot be treated as simply since there is a danger that the access charge will forestall consumption for some customers who cannot afford the fee In this case, Ramsey-Boiteux pricing can be employed to find a second-best solution Usage prices will in general exceed their marginal costs whereas access charges will be set below the marginal cost of access

MARKET-COMPATIBLE RATES (cont'd)

d An option may be to introduce new tariffs on a *self-selecting* basis while still offering the traditional tariffs. For instance, an electric utility could introduce a time-differentiated rate in addition to a non-time-differentiated rate and allow its customers to chose the preferred rate to be used for billing purposes

- Example· A local telephone company may offer two tariffs Tariff I consists of a $8 monthly charge plus 10 cents per call, tariff II consists of a $10 monthly charge and 6 cents for each call

  In this example, consumers placing less than 50 calls per month would benefit from tariff I whereas consumers placing more than 50 call per month would benefit from tariff II

5. An axiomatic approach to cost-based pricing

a. In this recently proposed approach, intuitively desirable features of an allocation scheme for common costs are listed as axioms. Starting from these axioms, features of prices can be developed that are consistent with the axioms.

b For example, Mirman, Samet and Tauman have proposed a set of six axioms for cost allocation in the short run (see the discussion in Brown and Sibley, 1986, pp 55)

- Axiom 1 (*cost sharing*): The firm should break even across all services

- Axiom 2 (*rescaling*): If the scales of measurement of the commodities are changed, then a sensible allocation mechanism should result in prices which change accordingly.

- Axiom 3 (*consistency*): All goods with the same marginal costs should be priced the same (even if their price elasticities differ).

MARKET-COMPATIBLE RATES (cont'd)

- Axiom 4 (*positivity*) If a cost function has higher marginal costs at any point than another cost function, the resulting prices should also be higher.

- Axiom 5 (*additivity*) and axiom 6 (*correlation*) state that common costs should be considered add-ons to the variable costs of each service in a way that correlates with their relative variable cost Stated differently, costs with relatively high variable costs should get a high share of the common costs allocated, too.

c Prices that meet those six intuitively plausible axioms are under certain circumstances equal to fully distributed costs based on the *Attributable Cost Method (ACM)* that allocates common costs according to the share of one service in the total attributable costs of the provision of all services.

6. "Smart" markets

a In partially deregulated and partially competitive utility industries the problem of allocating scarce transmission capacity to only imperfectly foreseeable demand may arise Examples are the demand for released capacity of pipelines or the use of broadband transmission services by a large number of users such as in the case of the Internet backbone

b The use of modern information technology may allow to establish "smart markets" (the term was probably coined by Jeffrey K. MacKie-Mason and Hal R Varian, "Some Economics of the Internet", unpublished paper, University of Michigan, Ann Arbor, 1993).

c In a smart market, information technology can be used to perform an allocation process known as a "Vickrey-auction" Every participant in the bid for scarce transmission capacity attaches his willingness-to-pay to his demand for capacity The smart market allocates the capacity at every point in time (during specific intervals) to the bidders that have exceeded the market clearing price

d The optimal strategy consists in revealing one's true willingness-to-pay By the nature of the auction, bidders will not be charged more than their notified price and, frequently, may be charged much less.

7. Sustainability

a In an environment with partial competition and open market entry, prices need to reflect marginal cost and be subsidy-free to prevent inefficient market entry.

b However, in certain cases, even the discussed pricing rules may not result in prices that protect the incumbent utility from inefficient market entry. Such a situation is called an *unsustainable* market structure Figure 7 portrays this phenomenon for the case of a natural monopoly (i e the cost function is still subadditive) operating in the rising part of the marginal cost curve and slightly above its minimal average costs.

c It is disputed how widespread such situations are in regulatory practice but it should [illegible] erning to carefully analyze the conditions for the opening of market [illegible]

8. P[illegible]ing of inputs sold to competitors: the efficient component pricing model (ECPM)

a Problem arises if providers of network facilities sell the use of these facilities at wholesalle to competitors for sale at retail (e.g., a local exchange company sells access services to a competitor)

b The optimal input pricing rule states that inputs should be priced equal to their average-incremental cost including all pertinent incremental opportunity cost

Session 9

COSTING AND RATEMAKING

(Appendix)

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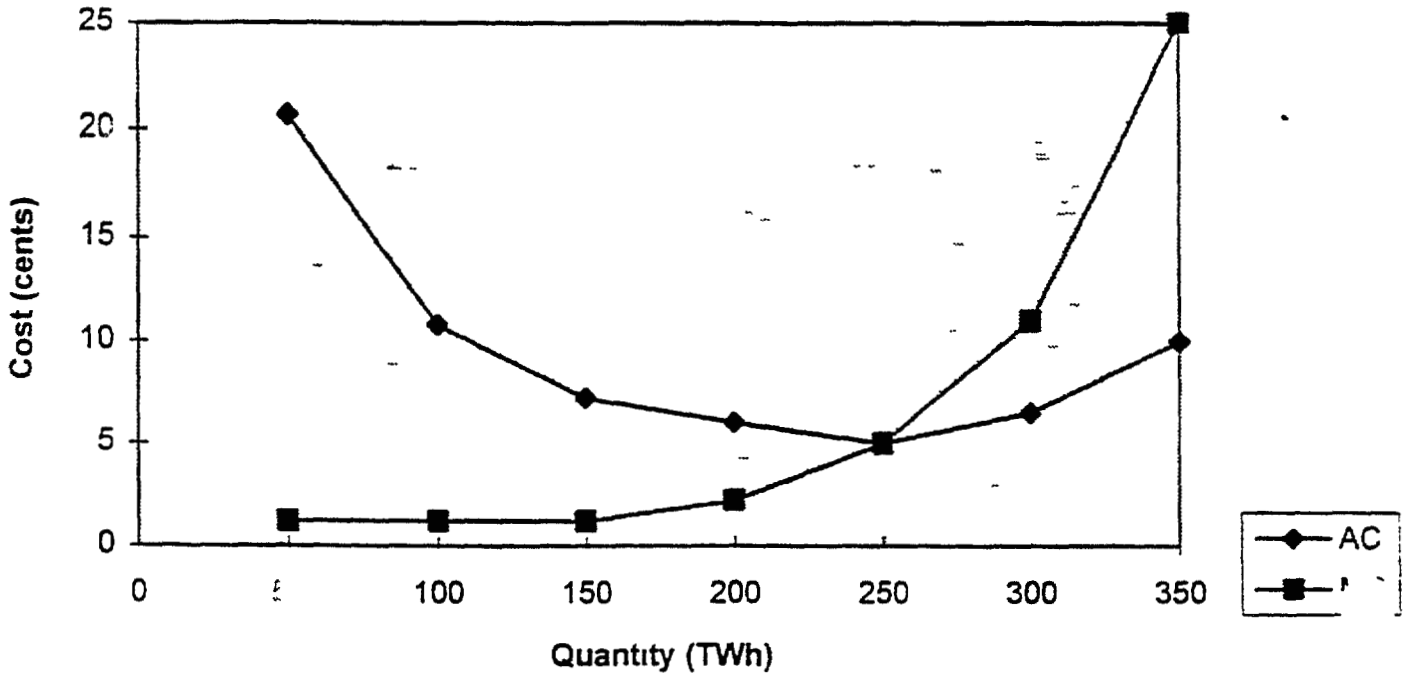
Basic Approaches to Pricing



Quantity	AC	MC
50	20 7	1 2
100	10 8	1 2
150	7 2	1 2
200	6	2 2
250	5	5
300	6 5	11
350	10	25

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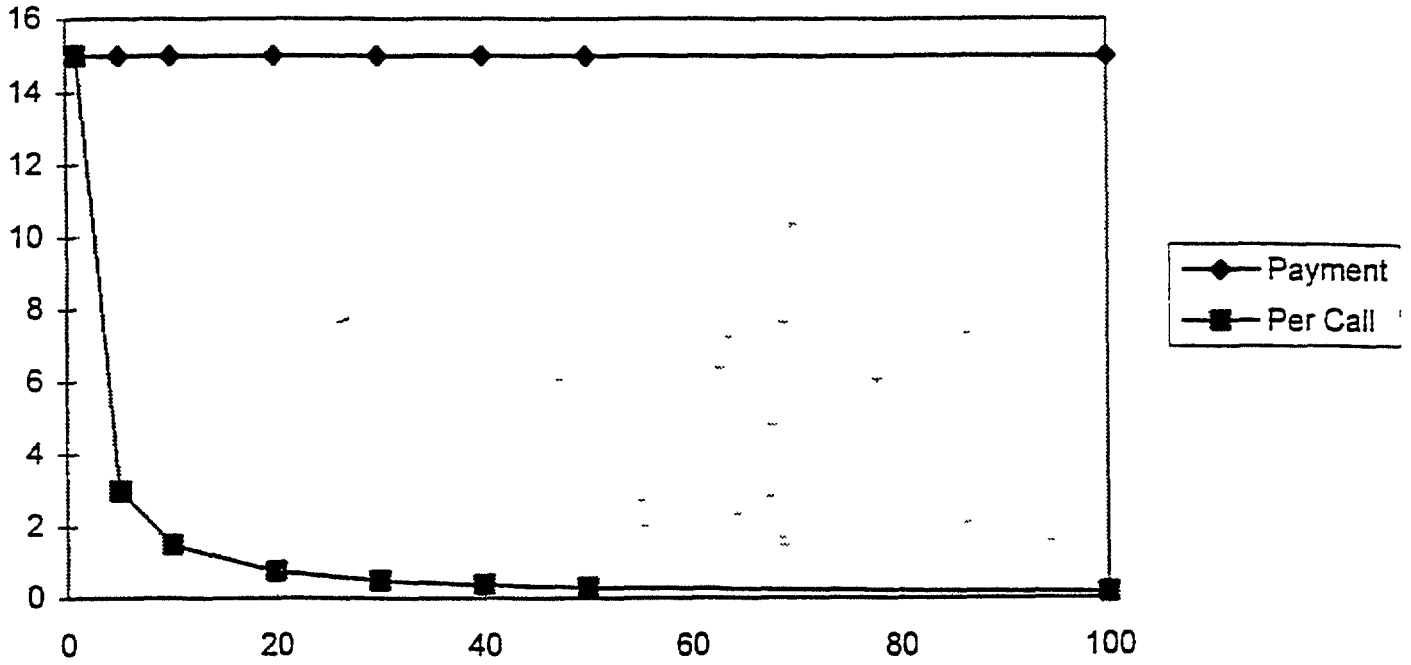
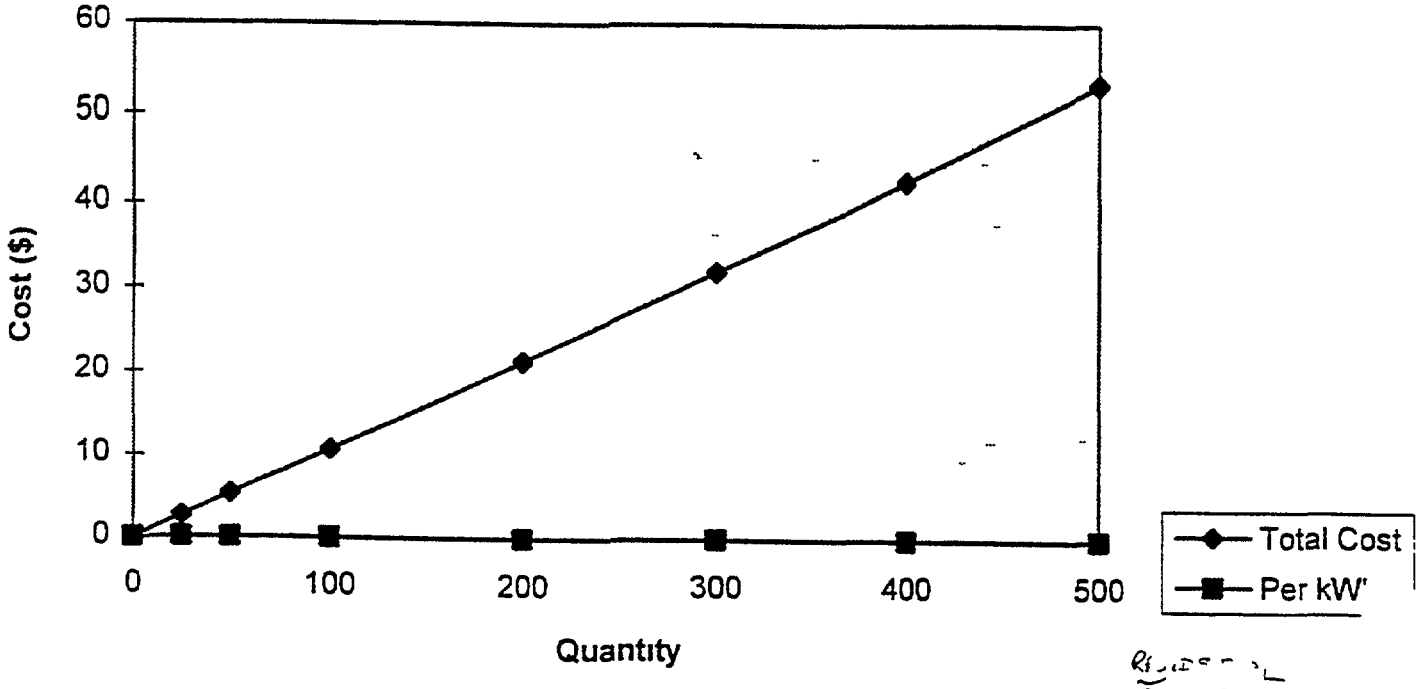
Flat Rate Tariff



$$RATE = \frac{R_P}{\#\text{ of calls}}$$

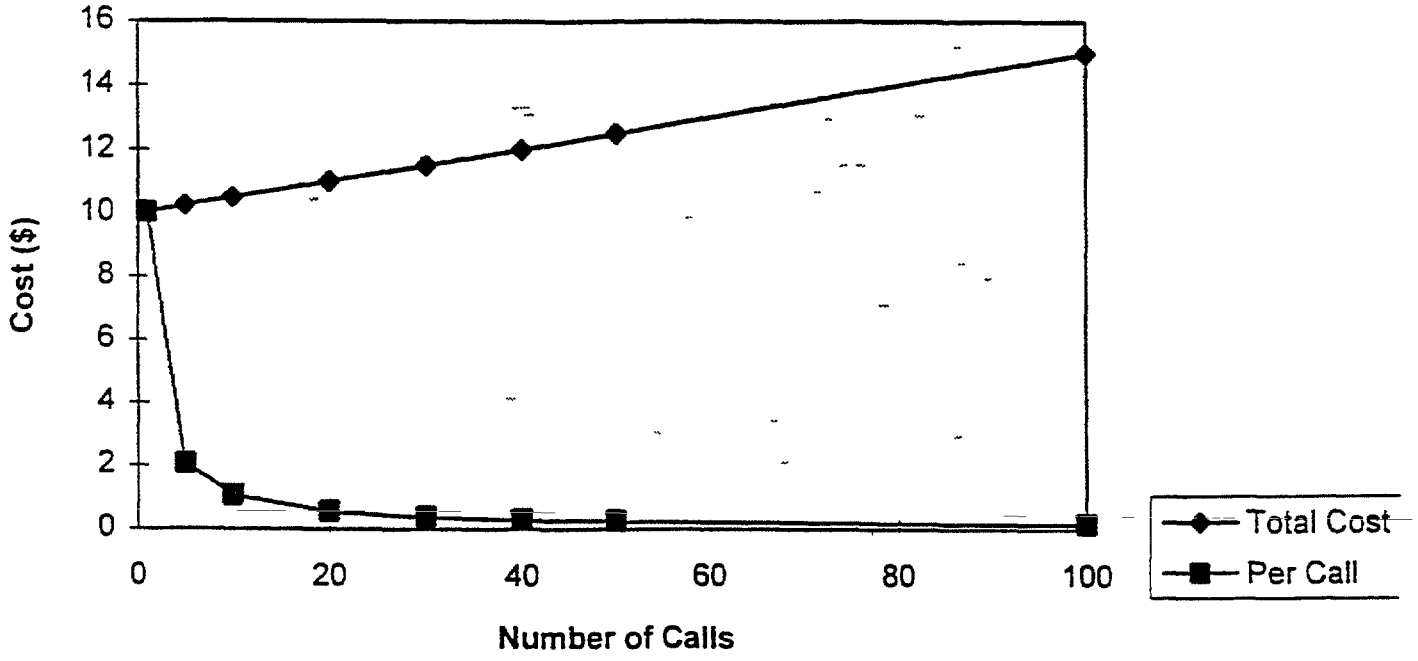
Quantity	Payment	Per Call
1	15	15
5	15	3
10	15	1 5
20	15	0 75
30	15	0 5
40	15	0 375
50	15	0 3
100	15	0 15

Linear Tariff



Quantity	Total Cost	Per kWh
0	0	0
25	2 67	0 107
50	5 35	0 107
100	10 7	0 107
200	21 4	0 107
300	32 1	0 107
400	42 8	0 107
500	53 5	0 107

Two-part Telephone Tariff



Quantity	Total Cost	Per Call
1	10 05	10 05
5	10 25	2 05
10	10 5	1 05
20	11	0 55
30	11 5	0 38
40	12	0 3
50	12 5	0 25
100	15	0 15

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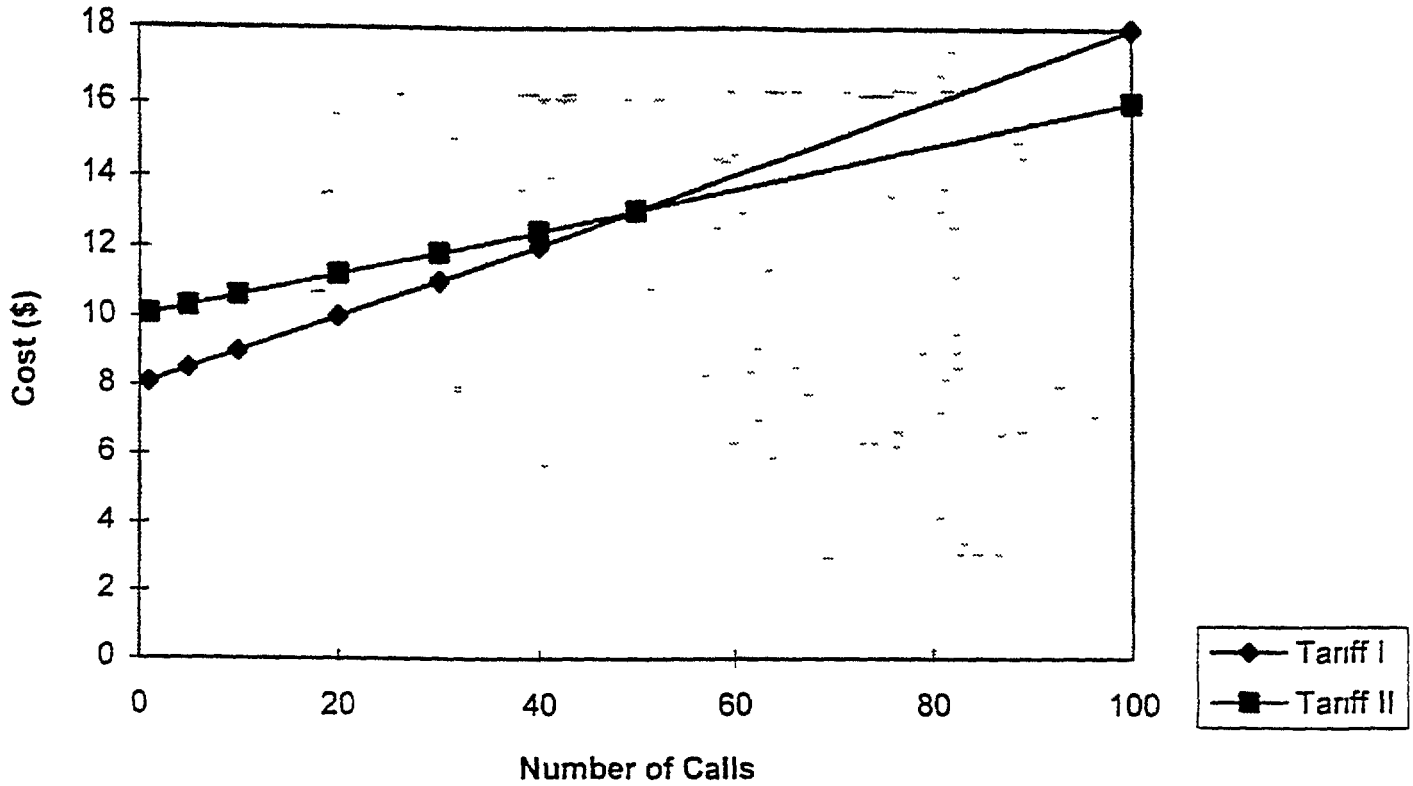
Self-selecting Tariff



Quantity	Tariff I	Tariff II
1	8 1	10 06
5	8 5	10 3
10	9	10 6
20	10	11 2
30	11	11 8
40	12	12 4
50	13	13
100	18	16

Accounting for Non-Accountants

by Ronald L. Kozoman, CPA

UTILITY FINANCIAL STATEMENTS

Welcome to the NARUC Regulatory Studies Program session on Utility Financial Statements. This session will attempt to give you an overview on how the financial statements are developed, how investors and creditors use them (what they tell you), and how they are used in regulation.

When a utility company requests permission to finance debt or equity, you have to analyze the utility's financial integrity to determine if it can service the proposed debt or equity. (pay interest and principal of the existing and proposed debt, and pay dividends on its existing and proposed stock). To determine the financial integrity, you would analyze the company's operating results (the Income Statement or revenues less expenses) to determine if it can service the additional debt or equity. Additionally, you would analyze the company's financial position (Balance Sheet) to determine the impact of the additional financing on a number of financial measures.

If the utility company is requesting a rate increase, you would use the Balance Sheet to determine the company's investment base (called a Rate Base) and determine what is financing that Rate Base, and the cost of financing the Rate Base (called cost of capital). You would also analyze the company's income statement to determine the allowed level of expenses.

The goal of this session is not to make all the participants accountants, rather it is to acquaint you with the financial statements and how to use them.

BALANCE SHEET

The first financial statement we will discuss is the Balance Sheet.

It is a Statement of Assets, Liabilities, and Equity at a specific point in time.

It is expressed as:

Assets = Liabilities + Equity, or abbreviated as:

$$A = L + E$$

The assets, liabilities, and equity accounts are considered to be permanent accounts. The balances of the assets, liabilities and equity carry forward from year to year. (This will make more sense when we discuss Revenues and Expenses.)

Assets are things of measurable value. Assets include cash, accounts receivable, materials and supplies, and plant, fixed or long-term assets. Assets are normally classified (subdivided into additional categories) as current and noncurrent or long-term.

Liabilities are moneys owed to creditors, or the creditors claims on the assets. Liabilities include accounts payable, wages payable, interest payable, bonds payable. Liabilities are normally classified (subdivided into additional categories) as current and non-current or long-term.

Equity represents the owners' claims on the assets. Equity includes accounts such as common stock, additional paid in capital, retained earnings, proprietorship capital, and partnership capital. Equity is classified (sub-divided into additional categories) as paid-in capital and retained equity.

In total, Assets, the things of value are EQUAL to the claims on these assets by the creditors and by the owners.

The term Balance Sheet is used, as the Assets BALANCE to the total of the Liabilities and Equity.

ASSETS = LIABILITIES + Equity

As an example, the owners of the utility start the business by investing $100,000 of cash into the business. The "entry" or the method used to record and/or recognize this transaction on the company's books and resulting balance sheet is:

Cash + $100,000 = Equity + $100,000

The Balance Sheet after this transaction is:

Assets $100,000 = Equity $100,000

Utility plant in the amount of $80,000 is purchased for cash. The "entry" to recognize this transaction is:

Plant In-Service	+ $80,000	
Cash	- $80,000	
Total assets = no change		Liabilities = no change
		Equity = no change

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The Balance Sheet after this transaction is:

Assets:		Equity:	
Cash	$20,000		
Plant In-Service	80,000	Equity	$100,000
Total Assets	$100,000	Total Equity	$100,000

Additional utility plant is purchased on credit for $70,000. The "entry" to recognize this transaction is:

Plant In-Service + $70,000 Liabilities + $70,000

The Balance Sheet after this transaction is:

Cash	$ 20,000	Liabilities	$ 70,000
Plant In-Service	150,000	Equity	100,000
Total Assets	$170,000	Total Liabilities and Equity	$170,000

From the above transactions, Assets can be increased by equity investments, or by incurring liabilities, or by selling a product or service at a profit (discussed when we review an income statement).

A Balance Sheet can be prepared at the end of the year, month, day, or any other point in time. The assets, liabilities and equity represent the balances at that point in time.

Most Balance Sheets you have seen start with the most current asset, which is cash, and proceed to the least current assets, which are termed plant assets, long-term assets or fixed assets. Cash is the most liquid of assets, and the ranking of assets is normally done in the order of liquidity. The liabilities come next, and are listed in the order in which they will be paid or liquidated (current liabilities, to be paid in less than a year, to long-term liabilities, which will be paid over many years from today). The next category on the Balance Sheet consists of the owners' equity section. The last category are deferred credits.

Utility company Balance Sheets are organized with the Plant In-Service as the first series of assets shown, followed by current assets, and then deferred debits.

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The Liability / Equity side of the Balance Sheet starts with Equity, followed by long-term debt, then current liabilities, and ends with deferred credits.

There is a reason for this. The Plant-In Service is an element of the investment made by the utility company (called a RATE BASE) on which the rates charged for the service rendered by the utility company are set. The Equity and the Long-Term Debt finance this investment, or rate base. As we go on, you will see that the placement of the Plant, Equity and Long-Term Debt was done for a reason. It tells the reader of the financial statement what is the investment, and what is financing that investment. Eventually, we will take the plant, other investment allowances, less the non-investor supplied plant, to determine the rate base. Then we will use equity, and long-term debt and prepare to determine the appropriate level of earnings allowed on the utility's investment or rate base. (The rate base and capitalization schedules will be done in the Revenue Requirements Practice Problems Sessions)

DIFFERENCES IN BALANCE SHEET FORMATS

Non-Utility Company	Utility Company
Current Assets:	Plant Assets:
Cash	Plant
Accounts Receivable	Less· Accum. Depr.
Materials and Supplies	Total Plant Assets
Total Current Assets	Current Assets:
Plant Assets:	Cash
Plant	Accounts Receivable
Less: Accum. Depreciation	Materials and Supplies
Total Plant Assets	Total Current Assets
Total Assets	Total Assets
Current Liabilities:	Equity:
Accounts Payable	Common Stock

DIFFERENCES IN BALANCE SHEET FORMATS

Non-Utility Company	Utility Company
Other Current Liabilities	Retained Earnings
Total Current Liabilities	Total Equity
Long-Term Liabilities:	Long-Term Liabilities:
Notes Payable	Notes Payable
Total Long-Term Debt	Total Long-Term Debt
Equity:	Current Liabilities:
Common Stock	Accounts Payable
Retained Earnings	Other Current Liabilities
Total Equity	Total Current Liabilities

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Deferred Credits
Total Liabilities Equity Deferred Credits
Total Liabilities & Equity

Let's take a look at a typical Balance Sheet, and then view as it would appear if it were the Balance Sheet of a Utility Company.

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Revenue Caps

Robust Competition Later

By Kenneth W Costello

The debate over restructuring the electric industry has encompassed a revisiting of the traditional rate-of-return (ROR) pricing model Parties of widely divergent interests increasingly advocate alternatives Under the label performance-based regulation, these new pricing models share the objective of strengthening incentives for electric utilities to pursue some specified socially desirable outcome Conservationists, for example argue that ROR regulation provides utilities with a disincentive to promote energy efficiency on the demand side of the meter[1] Economists also consider ROR regulation an inferior mechanism for promoting economic efficiency, especially when a utility lacks complete monopoly power[2] Overall, interest groups and independent analysts seem to agree that ROR regulation, at least in its current form, will not survive the transition to a more competitive power industry

Revenue caps are one alternative that has gained some credibility in the regulatory community[3] The major privately owned electric utilities in California as well as utilities in several other states currently operate under revenue-cap-type plans[4] Advocates argue that revenue caps operate similarly to price caps, but produce greater energy efficiency[5] Price caps, they contend, give utilities an incentive to oversell electricity—an outcome that runs counter to the objectives of a proconservation, environmentally benign industry

Increasing pressure to institute revenue caps leaves many state public utility commissions (PUCs) facing a choice between price caps and revenue caps—a choice between significantly different consequences Price caps are superior to revenue caps both in accommodating competition and in advancing generally accepted regulatory objectives[6] Further, revenue caps exhibit shortcomings that can seriously undermine the primary objectives of public utility

[1] See for example Eric Hirst "Regulatory Disincentives and DSM" *Public Utilities Fortnightly* (July 1 1994) 45-48

[2] See California Public Utilities Commission Division of Strategic Planning, *California s Electric Services Industry- Perspectives on the Past Strategies for the Future* (San Francisco CA. California Public Utilities Commission February 1993)

[3] In this article revenue caps denotes both revenue decoupling and net lost revenue adjustment mechanisms These mechanisms all break the link between sales and revenues. Specifically they allow utilities to increase prices when sales decline

[4] See John L. Landon, "Performance-Based Regulation presentation before the Regulatory Matters Committee of the Public Utilities Commission of Ohio Columbus OH, January 8 1996 and Robert J Graniere and Anthony Cooley *Decoupling and Public Utility Regulation* (Columbus OH The National Regulatory Research Institute 1994) Chap 2. Among the states are New York and until recently Maine and Washington.

[5] In Eric Hirst Eric Blank, and David Moskovitz "Alternative Ways to Decouple Electric Utility Revenues from Sales" *The Electricity Journal* 7 no 6 (July/August 1994) 47 the authors stated

> [I]nstead of price-cap regulation which would penalize a utility for running DSM programs commissions could implement revenue-cap regulation. Such revenue-cap regulation adjusted from year to year for inflation and productivity would encourage utilities to be innovative and aggressive in their cost cutting, while ensuring that shareholders are rewarded for running cost-effective DSM programs

[6] See for example Wayne P Olson and Kenneth W Costello "Electricity Matters A New Incentives Approach for a Changing Electric Industry" *The Electricity Journal* 8 no 1 (January/February 1995) 28-40

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or Price Caps?

Means Healthy Choices Now

Regulator, heal thyself! But first, don't mistake snake oil for a miracle cure.

regulation As the electric industry moves toward competition, revenue caps are not only ill-advised, but unlikely to survive

Worse Than the Disease?

Utility regulation was formed to correct economic distortions that arise if a monopolist is constrained only by market forces Therefore, its primary objective is to prevent the utility from pricing above costs, earning supranormal profits over a sustained period, and engaging in excessive price discrimination Over time, state PUCs have broadened their responsibilities—by promoting economic development within their states, for example—but mostly they have kept to their original mandate to enhance economic efficiency and ensure reliable and safe service

Revenue caps do not keep utilities in line with long-standing regulatory objectives To the contrary, revenue caps inflate prices above marginal cost, discourage utility marketing when economical, elicit underconsumption of utility services reduce incentives to provide high-quality service, and shift the risks associated with bad management decisions to consumers Perhaps most damaging for the future, revenue caps create utility incentives diametrically opposed to those that motivate firms in competitive markets As a ratemaking mechanism for achieving higher energy efficiency in the power industry, revenue caps are not only highly inefficient but socially detrimental

Figure 1 *(see sidebar on page 30)* depicts the short-run effects of a hypothetical revenue cap imposed on a competitive industry[7] Although the revenue cap was intended to improve consumer welfare, the outcomes prove quite the opposite The revenue cap places consumers and society as a whole in a worse position than before Further, the industry becomes less efficient, as well as more profitable under certain conditions The industry s overall performance also moves closer to an

[7]The analysis of revenue caps presented here follows the analysis of rent control as a revenue constraint. In the real world the ceiling on rents represents a constraint on the rents allowed for a housing unit—*i e.* the price of housing services times the quantity of housing services. *See* for example Mark Frankena Alternative Models of Rent Control *Urban Studies* 12 (October 1975) 303-08 and Richard Arnott "Time for Revisionism on Rent Control" *The Journal of Economic Perspectives* 9 no 1 (Winter 1995) 99-120

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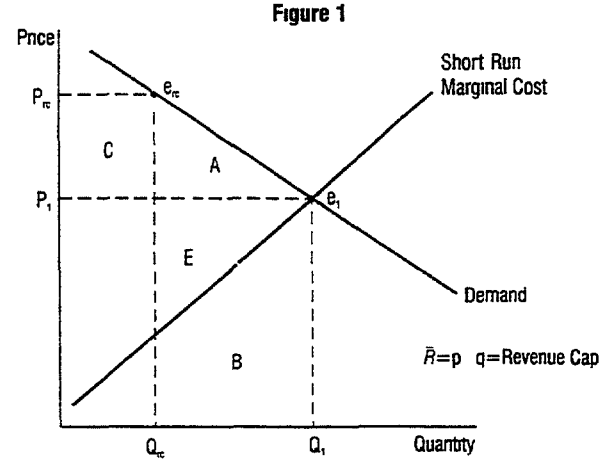
Capping Revenue Why It Shrinks Consumer Welfare

Unconstrained by governmental controls, a competitive industry would produce Q_1 at a market price of P_1 where the demand curve intersects the short-run marginal-cost line [a]

Now suppose that a revenue cap $\bar{R}$, is imposed to reduce the total bill of consumers (from P_1Q_1 to $\bar{R}$) The cap applies to all possible price-quantity pairings The rectangular hyperbola $\bar{R}$ maps pairs of price and quantity equal to the revenue cap (*i e*, restricting the price-quantity combination at or below $\bar{R}$) [b]

Under such a revenue cap, the industry would tend to operate at e_{rc}—the market-equilibrium and profit-maximizing point—with price set at P_{rc} and output equal to Q_{rc} [c] At this point the revenue-cap curve intersects the demand curve If output exceeds Q_{rc} revenues remain at $\bar{R}$ but total costs increase resulting in lower profits Output below Q_{rc} also reduces profits, because the revenue cap no longer binds and marginal revenue exceeds marginal cost.[d]

Figure 1



Outcomes

▲ Total economic welfare declines by area A+E (the so-called "triangular area" of welfare economics) as higher price causes consumers to reduce consumption

▲ Consumers suffer a welfare loss (area C+A) even though consumers spend less ($P_1Q_1 - \bar{R}$) and the industry incurs a lower total cost of service

▲ Pricing becomes inefficient because the new price (P_{rc}) lies above marginal cost

▲ Industry profits become volatile since the decline in costs may be more or less than the decline in revenues (area C versus area E) If the revenue cap equals the industry's prior revenues (*i e* $P_1Q_1 = \bar{R}$) the industry always profits The industry obtains the same revenues from producing less and thereby, incurring lower costs

[a]This is represented by the equilibrium point e_1

[b]A rectangular hyperbola plots the product of two variables as a constant In the context of our analysis the product of price and quantity equals $\bar{R}$

[c]It can be shown that at the equilibrium point e_{rc}, the industry supply curve intersects the market demand curve The industry supply curve corresponds to the revenue cap at prices where short run marginal cost lies above the revenue cap

[d]Below Q_{rc}, marginal revenue equals price which exceeds short run marginal cost

environment in which individual firms possess market power

Figure 2 *(see sidebar on page 32)* illustrates the effects of a revenue cap imposed on a declining-cost electric power industry As in the previous scenario 1) consumers are worse off 2) total economic welfare declines, 3) prices move farther from marginal cost 4) average cost rises, and 5) the utility enjoys higher profits in the amount of the reduced costs

A cap set below prior revenues (as in Figure 1) produces fairly similar results—although the utility s profits may not increase In other words, these adverse outcomes hold true even when consumers pay *lower* bills and the utility faces *lower* total costs

Flawed Diagnosis?

Clearly, a reduction in total bill and total costs does not, as revenue-cap advocates claim also ensure progress toward social or

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All other factors remaining constant, consumer welfare rises and falls inversely with unit price—not with the total bill.

regulatory objectives State regulators could inflict great harm on the general public by approving a revenue-cap plan, especially in a time of increasing competition in the industry

First, total bill is a flawed measure of consumer benefits Revenue caps presume that consumers always benefit when their electricity bills decline Yet electricity consumers directly benefit from greater quantity and quality of electric service Thus, a consumer with a lower electricity bill may actually receive lower net economic benefits from the consumption of electricity than other consumers

Consumer welfare is properly measured as consumer surplus —the value received from a product or service minus the expenditure outlay For example if price falls and the price elasticity of demand exceeds one, both the total bill and the consumer surplus would increase Since consumers are undeniably better off when price falls, price, rather than total bill, correlates with consumer welfare That is, all other factors remaining constant, an unbroken inverse relationship exists between consumer welfare and the price of a product or service This relationship does not hold true between total bill and consumer welfare

Second, revenue caps tend to produce higher prices than price caps or ROR regulation. Price-sensitive customers suffer because utilities become reluctant to offer discounted rates As additional consumption increases total costs by more than total revenues, utilities find little incentive to offer prices that reflect actual market conditions

In fact, utilities find clear disincentive to reduce prices for core customers or services (where the price elasticity of demand is less than one) Lowering price to increase consumption would increase total costs while reducing revenues causing profits to decline This result holds true even if the existing price exceeds marginal cost In other words revenue caps discourage utilities from expanding sales even under economical conditions (*e g*, surplus capacity), because they truncate the marginal revenues actually received by the utilities

Third, revenue caps convey improper price signals by widening the price/marginal-cost cap When consumption falls, for example, utilities could increase price even though marginal cost falls or at least stays constant The ability to raise prices when demand falls obviously runs contrary to a well-functioning electric power market

Fourth, revenue caps deemphasize the role of prices in utility markets Competitively motivated, efficient utilities do not attempt to directly minimize a consumer s bill market forces compel them to set prices at marginal cost or some other profit-maximizing level The other component of total bill, consumption, depends on consumer response to the price, as well as the quality of service

Fifth, revenue caps encourage utilities to reduce total rather than unit (average) costs Additional sales under a revenue-cap regime tend to cause total costs to increase by more than total revenues [8] Thus, utilities gravitate toward practices that reduce rather than improve sales They tend to operate to the left of the minimum point on their average-cost curves, because of the distorted price signals provided to consumers Over time, technological change would suffer, since productivity

[8] This may not always be true A technological change could simultaneously increase sales and reduce total costs if it causes the cost curve to shift down far enough

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Tying Caps to Rate of Return. No Better

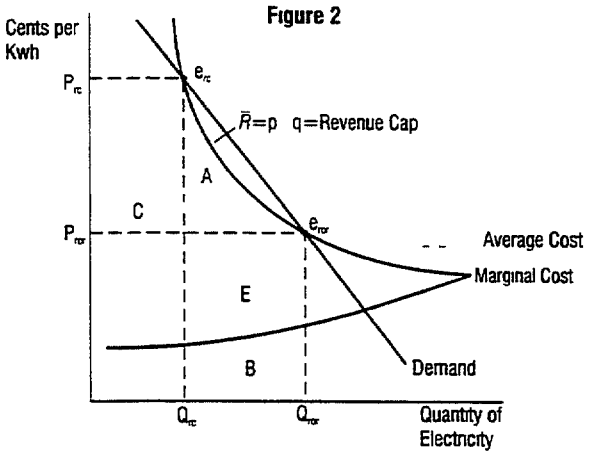
Assume that the cap constrains revenues at their prior value (*i e* $\bar{R} = Q_{ror} \times P_{ror}$) * Under rate-of-return regulation, the firm would price at average cost (P_{ror} = AC) produce at Q_{ror}, and earn a normal profit As in Figure 1 equilibrium lies at e_{rc}

Outcomes

- ▲ Consumers are worse off (by area C+A)
- ▲ Total economic welfare declines (by area A+E)
- ▲ Prices move farther from marginal cost
- ▲ Average cost rises
- ▲ Utilities profit by the amount of the reduced costs (area B)

These adverse outcomes generally apply even when consumers pay lower bills and the utility incurs lower total costs

Figure 2



This assumes that the price elasticity of demand between the relevant points on the demand curve equals one In Figure 1 because revenues decline in moving from point e_1 to point e_{rc}, the price elasticity of demand between these two points exceeds one

improvements are largely driven by a company's expectation of selling more products or services as it reduces its average cost Revenue caps negate this motivation

Sixth, revenue caps can cause volatile price changes Utilities can vary their prices according to changes in consumption Competitive markets do not permit a company to increase its price when demand falls In efficient markets, declining demand translates into declining prices Since utility sales could fluctuate widely from year to year in a more competitive market, revenue caps will likely result in more unstable and unpredictable prices

Seventh, revenue caps induce excessive energy conservation on the basis of a market test. Competitive markets rely on a market test to evaluate the need for energy conservation, revenue caps however, rely on a cost-effectiveness test [9] A market test offers utilities no incentive to promote energy conservation unless marginal cost exceeds price [10] The cost-effectiveness test, according to some analysts, provokes excessive energy conservation that cannot be sustained in a competitive environment.[11]

Although revenue caps promote cost-effective DSM,[12] their built-in bias elicits too much utility-funded DSM Their misplaced emphasis on minimizing DSM costs for a targeted level of energy conservation ignores the larger question How much DSM should a utility stimulate? Whereas revenue caps give utilities an incentive to overspend on energy conservation, price caps encourage utilities to produce at the level where marginal revenue equals marginal cost Where marginal revenue equals price, utilities are correctly motivated to sell more when price

[9]The cost-effectiveness test says that a utility should invest in energy conservation when it is less expensive than an 'equivalent' amount of electricity delivered to consumers.

[10]*See* for example Larry E. Ruff "Equity vs. Efficiency· Getting DSM Pricing Right" *The Electricity Journal* 5 no 9 (November 1992) 24-35 The market test would justify utility funded subsidies for energy conservation up to the difference between the marginal cost and the existing price as a response to a pricing failure (*i.e.* prices lying below marginal cost)

[11]*See* for example Douglas A Houston *Demand Side Management Ratepayers Beware!* (Houston TX. Institute for Energy Research May 1993)

[12]*See* for example The Regulatory Assistance Project "Performance-Based Regulation A Policy Option for a Changing World" *Issues Letter* (September 1994).3

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Price caps have been wrongly criticized for deemphasizing energy efficiency. In fact, they promote efficiency, but without shifting risk to customers for lost sales.

exceeds marginal cost, and sell less when marginal cost exceeds price

Eighth, revenue caps reduce a utility's incentive to maintain service quality Unlike price caps —which fall short in this regard, nonetheless—revenue caps enable utilities to increase price to compensate for lost sales due to poor service quality Utilities can do this as long as revenues do not rise above their previous level To a large extent, companies maintain service quality to avoid sales and revenue losses Revenue caps, however, enable utilities to increase price to compensate for lost sales due to poor service quality More disturbing, some utilities may even discover an incentive to offer lower-quality service If declining service translates into reduced output and costs, a utility could increase its profit by increasing price—a perversion that runs counter to sound economics and regulatory policy

A Second Opinion

Under revenue caps, energy efficiency comes at a high potential cost to consumers and society as a whole—at the cost of serious economic distortions The price is clearly too high Less perverse mechanisms are available if policymakers approach energy efficiency from both sides of the meter. Price caps offer such a mechanism.

Price caps have been wrongly criticized for deemphasizing energy efficiency In fact, price caps give utilities a strong incentive to innovate and to deploy supply-side facilities with greater energy efficiency Improved energy efficiency means lower costs, price caps reward lower costs by allowing a utility higher profits for a number of years Competitive markets provide a similar incentive

On the demand side of the meter, price caps encourage market-based energy efficiency by allowing a utility to price services as low as its marginal cost This flexibility, limited by the condition that prices cannot fall below marginal cost, ensures correct price signals

Price caps promote energy efficiency in a way that corresponds to market realities Revenue caps create incentives that are incompatible with both a competitive marketplace and generally accepted regulatory objectives As the electric power industry proceeds on a procompetitive path toward unbundled service and customer choice, revenue caps will prove increasingly inappropriate A competitive market has no use for a mechanism that shifts the risks of lost sales to consumers, distorts price signals, promotes inefficient technologies, and produces excessive prices Indeed, a mechanism that fails to recognize the true barometer of consumer welfare (price) is fundamentally at odds with a market in which competition is for the consumer

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Real-Time Pricing: Paying at the Margin

Savings, yes. But some load-management techniques may imply trade-offs in service quality.

By Scott L Englander John E Flory
Leslie K Norford and Richard D Tabors

As facility manager for a large hotel, you browse your energy vendor s web site to view tomorrow s hourly prices But it seems your computer (pc) has already done some browsing of its own Since it s connected to your energy management system, your pc has already looked up the weather forecast and has logged on to the hotel s main computer to find out what rooms will be used Using this information, your computer is now churning through several billion operating scenarios to pick the least expensive energy strategy for the following day

A while later an incoming e-mail message describes the operating schedules for your facility s mechanical systems You see that while prices will skyrocket to over $1 per kilowatt-hour (Kwh) for a couple of hours in the afternoon, your pc has planned an operating scenario that will take advantage of bargain basement prices during the early morning hours to shift certain loads, and will run your auxiliary generators when the high prices kick in A comparison shows you that your total bill for the month will undercut what you would have paid under your previous conventional electricity rate You leave for the day, knowing that your energy bills will once more come in under budget

A fantasy? Perhaps but not far from today s reality At the core of this scenario lies the concept of real-time pricing, or RTP that electricity can be bought, sold, and traded in a way that takes into account variations in cost related to time and location [1]

In today s market, traditional flat or time-of-use (TOU) rates still predominate They reflect the supplier s marginal costs only in an average sense As such, they skew consumer behavior and create subsidies within and between customer classes By contrast, RTP offers a clearer economic signal, motivating customers to adjust patterns of use to match the utility s marginal costs

Customers show little incentive to shift or curtail demand at critical times if the swing in prices is too small

During the past few years, electricity providers have begun offering real-time prices, even while heavily regulated RTP or variable pricing rates are currently available at over one-third of the utilities that serve the 60 largest cities in the United States [2] Initially, such rates were used for load management (especially for local transmission and distribution constraints) More recently, RTP is seen as a tool to attract or retain customers

In a competitive retail market, RTP will likely become the dominant foundation of electricity market transactions Wholesale spot prices will in all likelihood serve as the basis for the energy component of retail RTP

The California Public Utilities Commission (CPUC) envisions retail customers having the option to receive hourly prices that reflect the changing wholesale prices of the Western Power Exchange The CPUC also envisions retail customers making use of contracts for differences forward contracts and other risk management instruments similar to those

[1] Fred C Schweppe Michael C Caramanis Richard D Tabors and Roger E. Bohn 1988 *Spot Pricing of Electricity* Boston. Kluwer Academic Publishers
[2] CSA Energy Consultants Inc 1996 *Real Time Pricing and Variable Pricing Rates a 1996 Survey* Arlington VA.

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Energy Management at the Marriott

Juggling Fuels in an Earthquake Zone

Bill Kane, energy management coordinator for the 1 5 million square foot San Francisco Marriott Hotel is an ardent fan of real-time pricing Energy accounts for 50 percent of his budget: "When electricity costs $1 50 a kilowatt-hour, it makes you look a lot harder to find things you can do in response "

One strategy Kane "precools" the chilled-water loop on a day when electricity prices will climb sharply He then shuts off the chillers when the prices actually rise He uses a similar thermal storage technique to precool meeting rooms and also increases the discharge air temperature for these rooms when prices are high

Running emergency generators when prices are high simply was not an option for Kane Air-quality requirements limit the use of diesel fuel and natural gas can't be used as an emergency fuel in areas subject to earthquakes

Kane recognizes the labor required to respond to RTP, and the need for automation Yet, savings from RTP have helped the Marriott to invest in more efficient air-handling equipment.

Praxair Plays the Spread

Waiting for 10-1 Odds

Praxair the largest producer of industrial gas products in North and South America (300 plants in 50 utility service territories) uses real-time pricing (RTP) not only to dispatch systems and resources but also to coordinate operations between geographically separate plant sites In fact, it has developed RTP modeling software to schedule its plants that integrates data on all variable costs—including electricity transportation and the option of purchasing product from their competitors While only a few utilities offer the RTP to Praxair its electricity expenditures are high enough (70 percent of production cost) to justify price-based production scheduling in all plants with loads in excess of 2-3 megawatts

Says George McFadden, corporate energy manager at Praxair "As utility customers gain access to true variable pricing, they will then have the incentive to change their behavior

"Today we predominantly see price spreads (on-peak to off-peak) of three to one or at most five to one A dynamic competitive market for electricity with RTP will offer price ratios of ten to one," says McFadden "[which] will enable commercial and industrial customers to essentially "unbundle" electricity costs

"It will eventually change the way we design our plants and view our markets "

available to wholesale customers

Thus, RTP will retain a role as the market evolves The basis of prices will shift from the production costs of the local utility to those of the regional wholesale market As the CPUC has noted, the opportunities for improving asset utilization and cost control in this capital-intensive industry still remain [3]

Attributes Real Time vs Time of Use

The details vary widely, but RTP plans share several common factors Real-time retail electric prices typically do not change frequently in real time, but tend to remain constant for periods that range from a half-hour to five hours (hourly being typical) The customer usually receives energy prices a day ahead though forecasted prices may be available earlier. Hourly meters record loads, and the utility bills the customer monthly Consumers receive notice of prices via fax, modem, e-mail, and more recently, the World Wide Web Hourly prices typically fall below average for much of the time, shooting up to high levels—perhaps a dollar or more per kilowatt-hour—only for short periods which may represent only 1 or 2 percent of all hours each year.

Most current RTP rates are designed so that if the customer does not deviate from baseline' (*i e*, pre-RTP) operation, he or she will see no change in total electricity cost In other words, from the utility s perspective, the rate stays revenue-neutral if the customer (or class of customers) does not alter consumption patterns Deviations from the baseline load profile will increase or decrease the bill, depending on the hourly price at the time they occur.

So why don t traditional TOU rates offer enough of a price advantage?

Experience with traditional TOU rates has demonstrated that customers see little incentive to shift or curtail demand at critical times if the swing in prices is too small Likewise, the customer becomes less able to respond when high prices remain in effect for too many hours during the week. Fixed-demand charges based on the customer s monthly peak provide crude price signals at best, they can severely penalize short-term operation mistakes or equipment failures whether these occur at critical times or not

[3]The California Public Utilities Commission has described RTP as a triple win embracing the individual consumer of any class who is able to reduce costs by shifting load the society at large which defers the demand for new generation and investors in existing plant and equipment who see it put to more productive use *See Proposed Policies Governing Restructuring California s Electric Services Industry and Reforming Regulation Decision 95-05-045 May 24 1995 p 14 161 PUR4th 217 (Cal P U C) (notice of proposed rulemaking)*

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Curiously, such demand charges persist in many real-time rates Further time-differentiation in prices is needed for customers to effectively change their behavior

Commercial/Industrial Uses Some Trade-offs

Operators of energy-using facilities can take advantage of RTP to control mechanical systems in response to price Common price-control techniques fall under several general categories

▲ **Storage** Shifting energy purchases from high-priced periods Relying instead, for example, on central thermal storage for cooling, or (for industrial facilities) on storing intermediate product

▲ **Fuel Switching** Switching between an electric chiller or a chiller driven by a gas-fired engine, for example

▲ **On-site Generation** Using auxiliary power when (marginal) electricity prices exceed the operating cost of the generator

Other response strategies may involve a trade-off between cost mitigation and service quality, especially when energy managers must decide which loads are noncritical or choose among resources that offer different levels of service quality to meet the same need

▲ **Curtailment.** Cutting back on noncritical uses (*e g*, lighting) when prices exceed a given threshold

▲ **Distributed Storage** Precooling a building s thermal mass or frozen product, for example

An energy manager might use some of these same approaches to minimize energy costs for a group of buildings or facilities—perhaps by scheduling production in different plants at various times, while weighing time-specific electricity costs at each location, as well as transportation costs An oil pipeline, for example, could dispatch its pumping stations in different utility territories to minimize cost A producer of industrial gases could plan production in the same manner

However, the flexibility and innovation implied by these techniques comes at the expense of a demand for increased vigilance knowledge, and computational skills on the part of the facility operator Computer-assisted tools can help fill that gap allowing operators to inventory loads and assess control strategies as well as perform the necessary numerical computations In all likelihood as RTP proliferates, energy infrastructure equipment more and more will arrive equipped with intelligent control systems that can incorporate electric price changes in their operation

An oil pipeline might dispatch its pumping stations in 14 utility territories using real-time electric prices.

The Residential Class Enough Load to Matter?

Undoubtedly, some customers may receive little benefit from RTP, or find such pricing burdensome They may even constitute a significant market Other customers may prove willing to 'play the market,' but only if they are guaranteed some level of price certainty

Energy service companies might well serve such markets by offering consumers a range of packaging options that enable them to choose the level of price volatility (or supply interruptibility) that best fits their needs TOU rates will likely become more refined In general, on-to offpeak price spreads will increase the onpeak period will be defined more precisely critical days for the utility will be specially priced

Improved technology in telecommunications and metering is already expanding the market to which RTP can be offered cost-effectively Home management systems will soon include energy management under RTP along with other functions such as security, video (TV), voice (telephone), and data (Internet, electronic payment) To provide such services, a number of electric utilities (*e g* Pacific Gas & Electric, Public Service Electric & Gas, Florida Power, Entergy, CSW, Detroit Edison, Wisconsin Electric, American Electric Power, and UtiliCorp) have entered into joint ventures with telecommunications firms (*e g*, TCI Cablevision Microsoft, AT&T, IBM, BellSouth, Ameritech) Residential customers (or their energy service providers) may well take advantage of RTP within the next decade ▼

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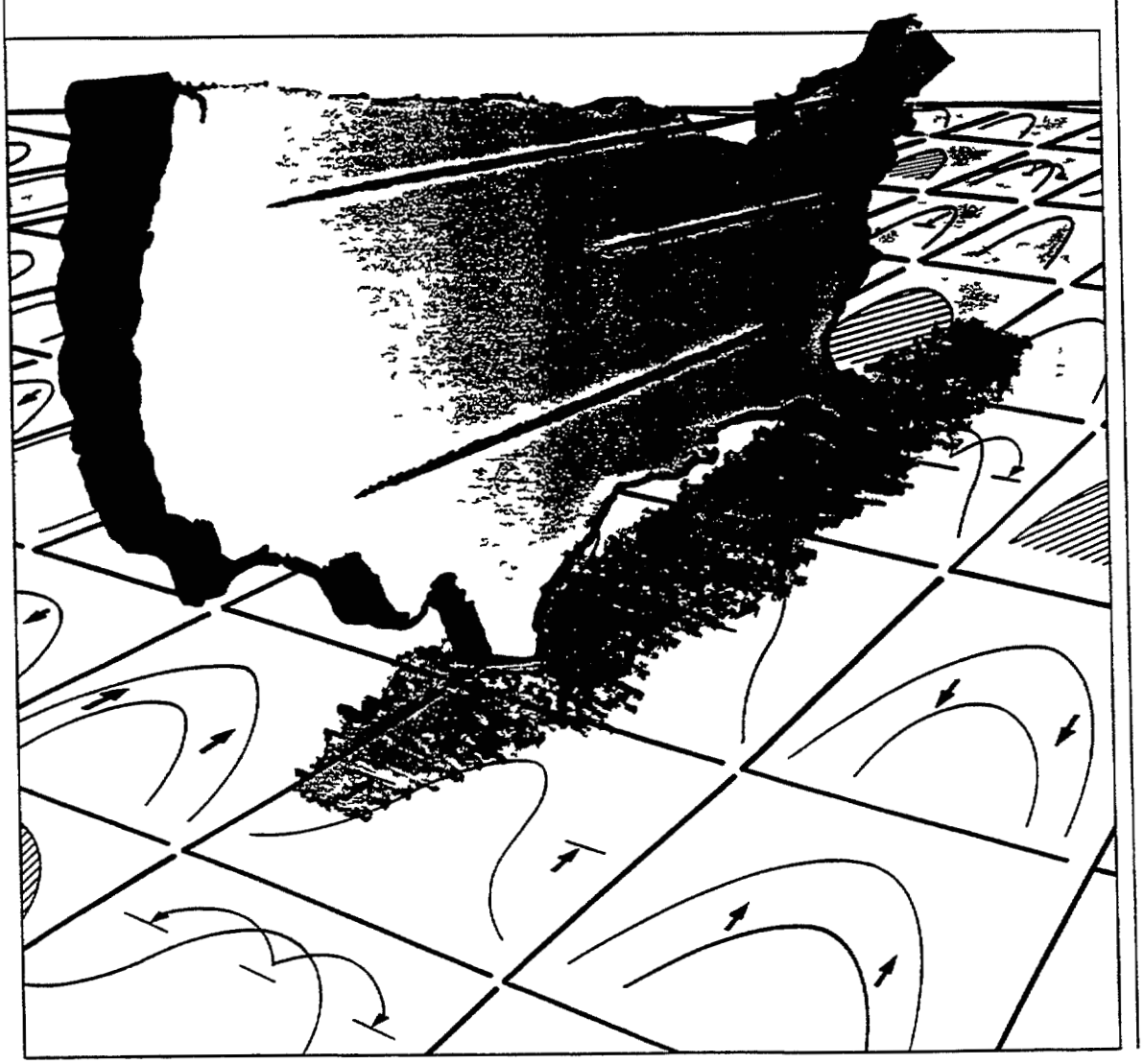
Demand-Side Management

Utility Options for the Future

EPRI



ELECTRIC
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Electric utilities—historically regarded as 'natural monopolies'— can no longer depend on predictable customer demand and sales protected by service territory boundaries Changes in the underlying economics of utilities as well as in policies that regulate them have created an environment of new competition—competition from other utilities from alternative energy suppliers and even from customers themselves

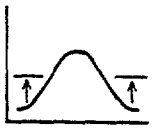
The seeds of economic change and competition were sown in the 1970s when a variety of unexpected events and social conditions combined to produce an unprecedented shift in the economics of utility operation For example, added regulatory constraints and double-digit inflation made it difficult to build new power plants High energy costs also fueled customer dissatisfaction with rates Subsequently, volatility in load shapes created new obstacles for predicting consumer demand and planning capacity additions After the 1973 oil embargo annual energy growth rates dropped from a historic 7 5 percent to only 2 4 percent per year signaling a need to alter traditional planning methods

In response to these pressures utilities are developing strategies flexible and diverse enough to promise success in an increasingly competitive and unstable market Specifically, utilities are extending their role as energy suppliers to include new emphasis on energy services Services that seek to actively influence the demand for electricity, i e , demand-side management (DSM) help ensure efficient utilization of resources and augment the range of choices available to customers and utilities in meeting the challenges and accommodating the uncertainties of the future

Peak clipping Perhaps the most common form of demand-side management peak clipping generally involves reducing system demand during peak-load hours to decrease peaking capacity and defer the need for new capacity Peak-clipping measures also can be used to reduce operating costs and dependence on critical fuels Utilities using peak-clipping measures are expected to reduce peak demand by about 17 gigawatts on the peak-load day in the year 2000

Expected Peak-Clipping Impacts *

DSM Program	GW on-peak	GW off-peak
Load Control	(4 1)	—
Time-of-Use Rates	(8 8)	—
Interruptible Rates	(4 0)	—
Total	(16 9)	

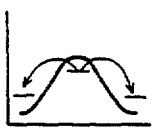


Valley filling. Many DSM programs are designed to increase demand during off-peak hours to better utilize capacity available at low operating cost and reduce average cost of service to customers The gigawatt impact of valley filling is similar to that of peak clipping However its energy impact is much greater because in contrast to peak clipping valley filling tends to affect every day s load shape not just that of the peak-load day As a result valley filling is expected to add 56 billion kilowatthours to annual electricity consumption during off-peak hours

Utilities undertaking valley-filling measures are expected to increase off-peak demand by about 16 gigawatts on the peak-load day in the year 2000

Expected Valley-Filling Impacts *

DSM Program	GW on-peak	GW off-peak
Thermal Energy Storage		4 1
Time-of Use Rates	—	8 8
Interruptible Rates	—	3 0
Total	—	15 9



Load shifting. Load shifting combines the benefits of peak clipping and valley filling for utilities and customers by moving existing load from on-peak hours to off-peak hours Utilities using load-shifting measures are expected to reduce peak demand by about 8 gigawatts and increase off-peak demand by about 8 gigawatts on the peak-load day in the year 2000

Expected Load-Shifting Impacts *

DSM Program	GW on-peak	GW off-peak
Load Control	(0 1)	0 1
Thermal Energy Storage	(4 1)	4 1
Time-of Use Rates	(3 3)	3 3
Total	(7 5)	7 5

The concept of demand-side management originated at the Electric Power Research Institute (EPRI) and is defined as the planning, implementation, and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in load shape Most utilities nationwide have initiated DSM programs The objective of DSM—to shape future demand for electricity in a way mutually beneficial for customers and utilities—applies equally to all utilities regardless of size location or ownership

Demand-side management can be effective in helping utility planners achieve their primary goal of matching electricity supply with demand In general, the expected impact of DSM is a reduction in demand for electricity This results from two generic types of DSM programs with countervailing influences those that reduce peak demand and those that increase it The former is expected to reduce peak demand by about 80 gigawatts over the years 1983 to 2000, while the latter is expected to increase peak demand by about 35 gigawatts over the same period—for a net 45-gigawatt reduction in what otherwise would be the peak demand in the year 2000

The variety of DSM programs in use—e g , load control time-of-use rates, interruptible rates thermal energy storage cogeneration, and sector-specific conservation and load growth—reflect utility-specific conditions and needs These programs can be roughly grouped under six generic objectives for control of load shape peak clipping, valley filling, load shifting, strategic conservation strategic load growth, and flexible load shaping

Strategic conservation. Strategic conservation programs encourage customer energy efficiency in selected applications to lower total system demand thereby deferring the need for new capacity and reducing average cost of service Utilities implementing strategic conservation measures are expected to reduce on-peak demand by about 56 gigawatts and off-peak demand by about 76 gigawatts on the peak-load day in the year 2000 These estimates include a reduction of 31 gigawatts from cogeneration Not all cogeneration is considered DSM—only that portion deemed to be utility induced and demand reducing

Expected Strategic Conservation Impacts *

DSM Program	GW on-peak	GW off-peak
Cogeneration	(31)	(31)
Sector-specific		
Residential	(5)	(9)
Commercial	(10)	(18)
Industrial	(10)	(18)
Total	(56)	(76)

Strategic load growth. These DSM programs aim to increase demand during selected seasons or specific times of day Like valley filling this increase in load can lower the average cost of service to customers by spreading fixed capacity costs over a larger base of energy sales Utilities initiating strategic load-growth measures are expected to increase on-peak demand by about 35 gigawatts and off-peak demand by about 25 gigawatts on the peak-load day in the year 2000

Expected Strategic Load-Growth Impacts *

DSM Program	GW on-peak	GW off-peak
Sector specific		
Residential	5	5
Commercial	5	10
Industrial	25	10
Total	35	25

Flexible load shaping. Some customers are willing and able to trade reliability of service for reduced rates or some other incentive By offering customers choices in the reliability of service utilities can adjust their load according to operating needs thereby gaining more flexibility in supply planning These types of agreements can enable a utility to avoid adding (or purchasing) peaking capacity To date flexible load shaping is the objective cited least frequently and no projections have been made for its impact on peak load in the year 2000

Estimates are for the peak load day in the year 2000 and reflect projections of numbers of customers participating in these programs

Load Shape Change: How Is It Achieved?

The DSM programs currently used to achieve load-shape objectives involve measures ranging from real-time manipulation of customer demand to offering customers incentives to use selected end-use technologies EPRI has undertaken several surveys to determine the types of residential and commercial programs in place and the degree of customer participation

Load control The most predictable DSM programs involve control of customers energy-using appliances Load control which can be accomplished through direct local or distributed methods can require installation of communications devices at both utility and customer facilities Direct control enables real-time alteration of customer loads by cycling or turning selected appliances on or off during specified periods Local and distributed control methods are customer-tailored allowing customers to make some or all of the control decisions Local control allows customers to control electricity costs and comfort through on-site controllers that operate in response to site conditions and utility rate structures Distributed control a combination of direct and local control link customers and utilities through a communication system by which utilities can relay real-time control commands electricity prices and other information Customers controllers can then respond to this information taking local conditions into account

Time-of-use rates Of the many special rate structures offered in DSM programs time-of-use rates are the most common By charging customers higher rates during peak demand hours (when operating costs are the highest) utilities encourage customers to conserve and to shift demand to off-peak hours

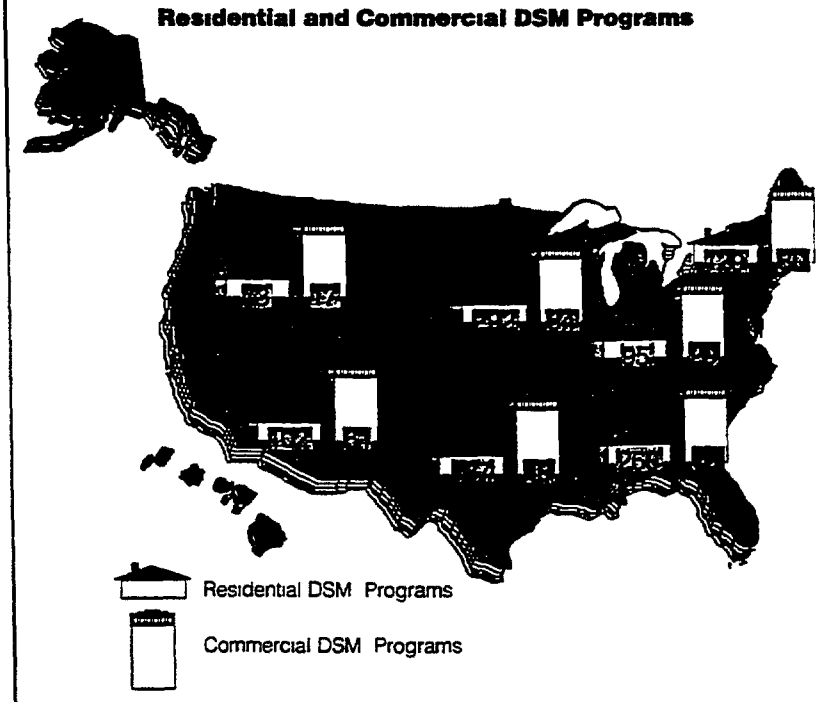
Interruptible and curtailable rates Interruptible and curtailable rates are the second most popular DSM rate structure In exchange for discounted rates participating customers—typically large commercial or industrial facilities—allow power to be turned down or off at their facilities

DSM Program Surveys

	Residential DSM Survey	Commercial DSM Survey
Utilities Responding	485	168
Programs Under Way	1 022	343
Participants	12 940,736	228 927

Recent EPRI surveys of utilities found over 1 300 residential and commercial DSM programs in place and over 13 million customers involved in some form of DSM The survey of residential programs was conducted in 1988 the survey of commercial programs was conducted in 1987

Residential and Commercial DSM Programs



Of the 1022 residential DSM programs currently active almost half are found in west central and southeastern states The 343 commercial DSM programs are more evenly dispersed with the least activity in the northwestern states and the most in west central states Some of the more common programs include load control thermal energy storage and innovative rate structures

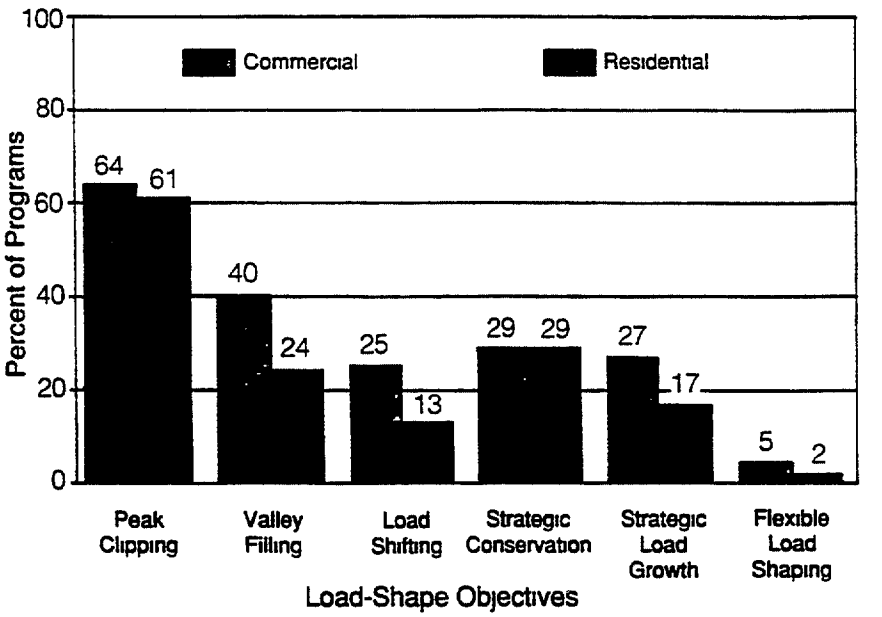
when it is needed elsewhere in the system The result is higher system reliability and greater utility control over large blocks of load

Thermal energy storage Customers install thermal energy storage (TES) systems to reduce on-peak electricity consumption These systems use off-peak electricity to cool or heat a storage medium and then draw from that medium to provide space cooling or space heating during peak hours TES systems offer customers energy cost savings where time-of-use rates or demand charges are in effect and help reduce utility peak loads Dual-fuel heating systems which use fossil fuels for peak heating needs and off-peak water heating systems also can help switch demand off peak

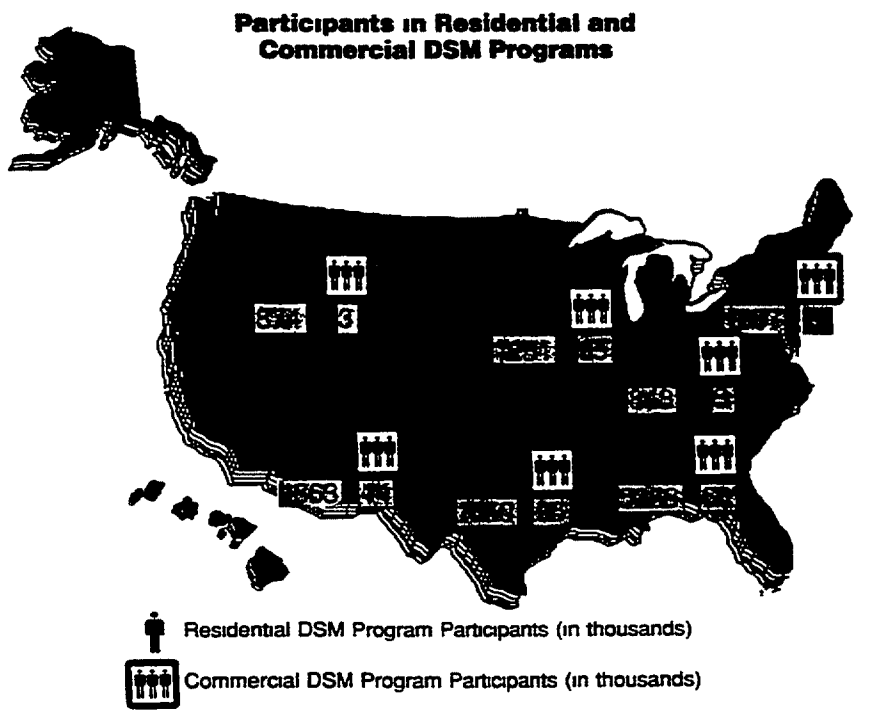
Cogeneration Where capacity is constrained some utilities are promoting customer use of cogeneration for on-site production of electricity Customer cogeneration reduces electric utility revenues but it can constitute a quick capacity addition where growth in demand is a priority concern

Conservation Energy conservation programs are frequently undertaken where capacity is constrained Generally these programs encourage customers to improve the thermal integrity of buildings and to use more efficient equipment and appliances in return for reduced energy costs High-efficiency electric technologies such as heat pumps multiplex refrigeration equipment and adjustable speed drives offer additional customer benefits of enhanced comfort efficiency and increased productivity in the workplace Utility benefits include a slowdown in total load growth

Load growth Utilities with ample capacity employ programs that stimulate new uses of electricity during selected times of day or seasons of the year For example security lighting promotions add nighttime load whereas add-on heat pump programs enhance wintertime load curves Both spread fixed capacity costs over a larger base of energy sales



EPRI survey results indicate peak clipping is the load-shape change objective most frequently reported by utilities implementing residential or commercial DSM programs



Two-thirds of the residential customers participating in a DSM program (nearly nine million customers) reside in western south central and southeastern states Enrollment in commercial DSM programs is greatest in south central southeastern and west central states (over 190 000 customers)

Alternatives to Utility Service Disconnection

CHAPTER ONE

BACKGROUND AND INTRODUCTION

Behind any discussion on whether there are desirable alternatives to utility service disconnection for residential customers who fail to pay their bills is an underlying debate on the proper role of economic regulation of public utilities The debate includes questions of whether state public utility commissions can or should expand their roles, often without expressed and explicit legislative mandate, beyond that encompassed by traditional ratemaking to accomplish social goals Some believe that the proper role of a state public service commission does not include the pursuit of social goals, whether those social goals be economic development or preventing social distress to low-income customers Pricing gas and electricity based on need rather than demand abandons cost-of-service pricing and makes utilities quasi-welfare agencies Others contend that it is appropriate for state public service commissions to provide or oversee utility provision of certain limited social assistance, such as budget counseling, referral services, and financial assistance, because they are aimed at preventing social distress, such as the disconnection of low-income residential utility service The outcome of this debate, however, does not require resorting to polar extremes The fact is that legislatures and commissions believe that the real question is to what extent should the public utility commission provide or encourage the utility to pursue social goals and to what end

The underlying assumption of this study is that commissions should encourage utility actions that minimize disconnections (thus maximizing service), provided those actions do not unduly adversely affect utility service arrearage and

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bad debt Preference is given to programs that minimize distortion of pricing and billing of services Preference is also given to programs that minimize the reliance on subsidies and utility class cross-subsidies

THE OCCASION

This study occurs as traditionally vertically-integrated electric and local gas distribution companies, under the jurisdiction of state public utility commissions, are facing increasing pressures to become more competitive by reducing costs These competitive pressures come from the more open and competitive wholesale electric and gas markets, where the commodity price of gas now fluctuates at market-driven levels and wholesale power is also becoming more market-driven

For gas utilities, this increased competitive pressures was facilitated by Federal Energy Regulatory Commission (FERC) Orders 436 and 636, which implement federal policies to provide access to the gas markets at the wellhead Orders 436 and 636 allow local gas distribution companies and, by state policy in most states, large industrial customers direct access to purchase gas at the wellhead With the deregulation of gas prices, the existence of a gas supply surplus, and the opening of wellhead access to gas producers, the stage was set for the development of robust gas markets Allowing large industrial customers to purchase gas at the wellhead helps to expose cross-subsidies that were implicit under traditional cost of service allocations However, most state commissions take these cross-subsidies into account either by allowing the local distribution company (LDC) (1) to implement "top-down" gas transportation pricing to collect the same fixed costs from a gas transportation customer as it does from gas purchase customers or (2) to enter into a special contract with a customer that may be willing and able to bypass the LDC

For vertically-integrated electric utilities, the enactment of the Energy Policy Act of 1992 (EPAct) facilitated the development of a more robust and open wholesale power market EPAct provides for mandatory wheeling of power to

wholesale power customers and allows the development of independent power producers (IPPs) that can meet certain requirements to qualify as exempt wholesale generators (EWGs) Thus, increased supply and demand for wholesale power are possible There are also many utilities with overcapacity, with power to sell on the wholesale power market These factors set the stage for the development of a robust power market, under circumstances in many ways similar to those that led to the development of a robust gas commodities market

However, in the case of vertically-integrated electric utilities, there is no requirement of retail wheeling to the ultimate customer Indeed, EPAct expressly forbids the Federal Energy Regulatory Commission (FERC) from ordering retail wheeling Instead, a savings provision of EPAct preserves the authority of state commissions to regulate or not to regulate retail franchise areas

As presented in Figure 1-1 below, traditional cost-of-service allocations usually result in an allocation of the cost of capital burden that favors residential customers over industrial customers However, as industrial customers are given choices, they will seek to drive down their cost of capital allocation As discussed below, they will also seek to escape the burdens of any demand-side management or social service programs that favor other customer classes

Further, as vertically-integrated electric utilities and local gas distribution companies find themselves under competitive pressures to provide services at the lowest possible costs, they will find it tempting to cut social service, conservation, and demand-side management programs Those programs do not directly contribute to their ability to deliver their product to the customer at the lowest price (Even if demand-side management programs can be demonstrated to result in a lower total bill for energy services, competitive pressures result in an effort to provide customers with the services that they want at the *lowest possible price*) Further, there are allegations by customers with choices (typically industrial) that they have to share in the cost of social service, conservation, and demand-side management programs while realizing very little corresponding benefit Instead, the major benefits of social service, conservation, and demand-side management

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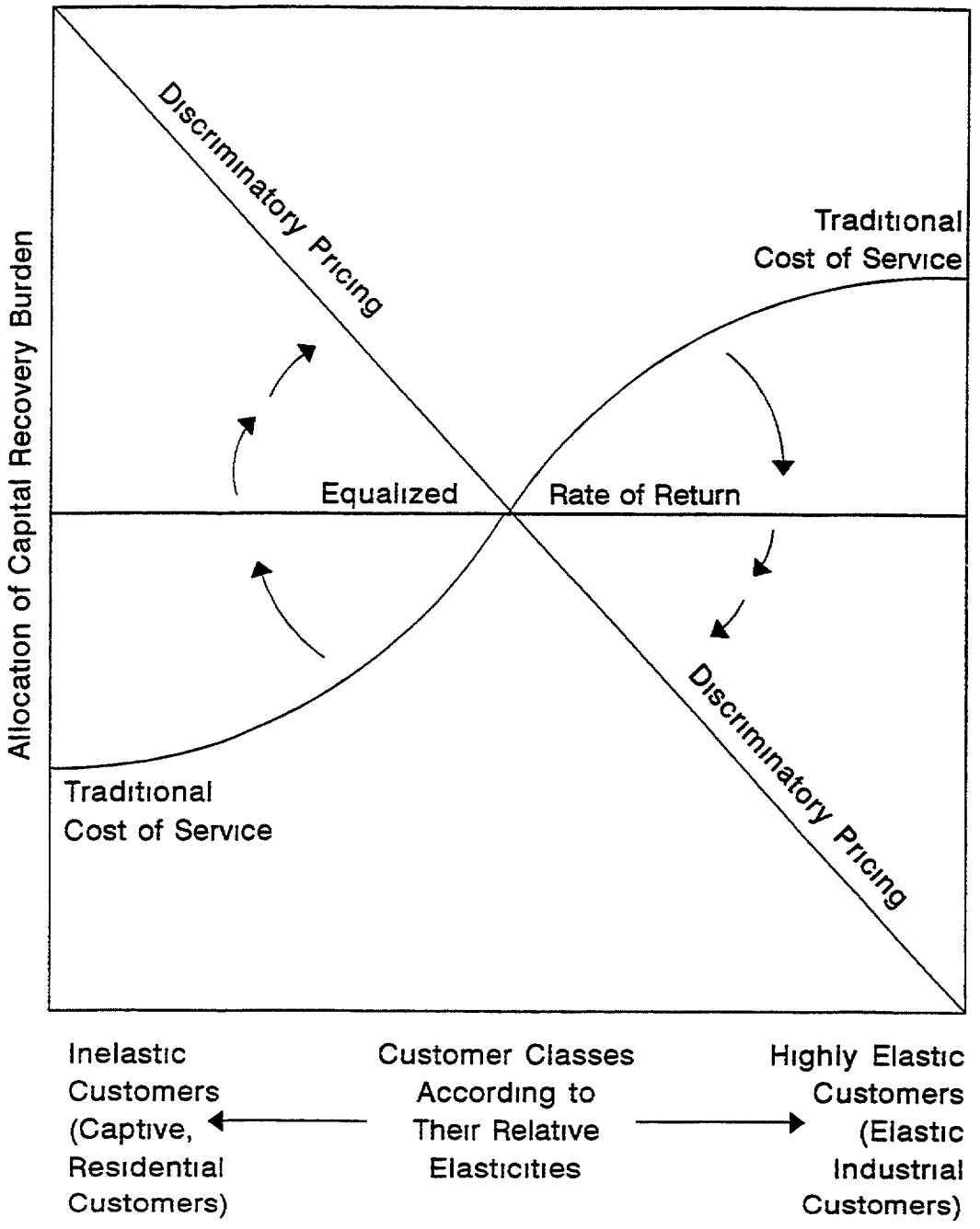

Fig 1-1 The ongoing shift in the allocation of capital recovery burden from industrial to residential customers Source Robert E Burns, The National Regulatory Research Institute's New Commissioner Tutorial

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programs are alleged to go to residential customers, who are typically thought of as core customers with few choices

This report is also occasioned by cutbacks in funding of federal social service programs, in particular, the funding of the federal Low-Income Heating Assistance Program (LIHEAP), the principal federal program providing federal funding to provide energy assistance to low-income customers Indeed, the Clinton Administration proposed to reduce the federal LIHEAP budget from $1 475 billion for Fiscal Year 1994 to $730 million for Fiscal Year 1995 LIHEAP funding provided energy assistance to an estimated 5 2 million households, or 14 million individuals in 1993 The proposed 49 percent cutback of LIHEAP funding would significantly affect the 70 percent of LIHEAP recipients who have an annual income of $8,000 or less, many of whom are elderly or single-parent households Although opposed in a Resolution of the Executive Committee of the National Association of Regulatory Utility Commissioners at its Winter 1994 Meeting, the proposed cutback on LIHEAP funding was passed by Congress Further cutbacks in funding of LIHEAP might possibly occur in the future

Indeed, in late February 1995 the House Appropriations subcommittee cut $1 319 billion for LIHEAP funding for Fiscal Year 1996, and in early March 1995, the full House Appropriations Committee voted to cut the LIHEAP funding for Fiscal Year 1995 The NARUC Executive Committee adopted a resolution at its Winter 1995 meeting, urging Congress to reject any cuts in or recision to LIHEAP funding and to adopt a LIHEAP budget as requested by the Administration for Fiscal Years 1996 and 1997 President Clinton vetoed a recision of current LIHEAP funding The current House Bill has no specific funding for LIHEAP Instead, LIHEAP would be rolled-in as a part of a "super grant" to the states The current Senate Bill will continue LIHEAP as a separately funded block-grant program at $1 3 billion Many believe that a compromise in the Conference Committee will occur, with the likely result being a cutback in LIHEAP funding

This report also deals with alternatives to service disconnections for water utilities Although there is no pressure placed on the water utility industry from

emerging competition, nevertheless, the development of state commission policies that require or encourage alternatives to water service disconnection has recently taken on increased importance In the past, water utility service has been taken for granted as a low-cost utility service, where service disconnection because of an inability to pay was an issue for only very few customers However, recent increases in the cost of water utility service, caused primarily by infrastructure replacement and secondarily by the cost of complying with the Safe Drinking Water Act as well as the increased demand of water, have made water utility services (drinking water, storm-water management, and waste-water services) less affordable, particularly for low-income residential customers No longer can the cost of water service be taken for granted Increasingly, low-income residential customers are finding it difficult to pay their bills and finding alternatives to disconnecting water service has become desirable

ORGANIZATION OF THE REPORT

This report deals with alternatives to disconnection for electric, gas, and water utility service Energy utilities are making a transition into a more competitive environment and these competitive pressures have direct implications on the appropriate regulatory approach to help assure that a utility either institutes or maintains an approach that provides alternatives to disconnection of energy utility services The realities of emerging competitive pressures may force hard choices and innovative approaches to maintain and enhance alternative measures to utility disconnection for electric and gas utilities

For water utility service, there is little indication of competition or impending competition Therefore, a more straightforward discussion of alternatives to disconnection is appropriate

Figure 1-2 shows which state commission staffs responded to the survey (As in other NRRI surveys three attempts were made to solicit a response from each state) In subsequent figures and tables, the reader should keep in mind that

Fig 1-2 States filling out the NRRI survey
Source NRRI survey results

the figure only shows those state commissions where a particular type of program is known to exist It does not necessarily mean that there is not such a program in a state that did not respond to the survey In subsequent figures, state commissions that have a program are shaded, those that do not have a program are left blank, and state commissions that did not respond are crosshatched In Table 1-1, the alternatives to disconnection to electric and gas utility service are enumerated and described Chapters 2, 3 and 4 of this report concerns an evaluation of the impact and effectiveness of programs that are alternatives to utility service disconnection for electric and gas service

The authors review the electric and gas service disconnection policies of the various states in Chapter 2, including prior notice requirements, winter restriction moratoria, date-based moratoria, temperature-based moratoria, prior commission approval requirements, and service limiters The pros and cons of each policy are presented In Chapter 3, the authors conduct a similar review of the billing and pricing arrangement policies of the various states that are presented as part of a strategy to create alternatives to electric and gas utility service disconnection The pros and cons of each policy are discussed In Chapter 4, the authors review nonprice, preventive, customer service assistance programs that help to create alternatives to electric and gas utility service disconnection The discussion also includes pros and cons of each policy Alternatives for utility disconnection for water service are discussed in Chapter 5 In Chapter 6, the authors provide an empirical analysis of the survey results of alternatives to utility service disconnections for electric and gas service Finally, in Chapter 7, the authors develop and discuss a positive alternative approach on how state commissions might create incentives for their energy utilities to actively pursue alternatives to utility service disconnection in an increasingly competitive environment and a positive approach toward developing alternatives to disconnection of water service in a monopoly environment

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TABLE 1-1

ALTERNATIVES TO SERVICE DISCONNECTION USED IN THE ENERGY SECTOR

Measure	Description
·ior notice	Formal notice given by a utility company to residential customers before terminating ·vice due to nonpayment.
Winter restrictions	·rocedures other than prior notice that restrict utility disconnection for nonpayment during the winter months
Date-based winter moratoria	Policies that prohibit winter service termination between during specified dates
Temperature-based moratoria	Policies that prohibit service termination when the temperature falls below a certain level
·ommission-approved ·isconnections	Policies that prohibit disconnections subject to approval of the public utilities commission on a case-by-case basis
Payment arrangements	A utility company arrangement in which payment-troubled customers pay arrearage in future installments in order to avoid disconnection or to reconnect utility service
mporary service guarantee	A short-term guarantee of service during the winter months if a payment-troubled customers pays a minimum amount of the monthly bill or a certain percentage of annual household income
dget billing	Level payments made throughout the year that allow the customer to defer costs of high energy consumption until later months when energy consumption is lower
yment extension	Deferral of a utility payment due date to coincide with a fixed-income customer s receipt of Social Security pension or other monthly income
·rrearage forgiveness	Forgiveness of arrearage for select low-income customers who have demonstrated a good-faith effort to pay their utility bills
·ifeline rate	A baseline rate that is less than the actual cost of service for the utility
Service limiter	A device that temporarily restricts a household s normal utility consumption
Below-market conservation loan	A below-market-rate loan from a utility to a low income residential customer for financing the installation of conservation measures
Utility funded weatherization	The use of utility funds to pay for the weatherization of low-income homes
Energy audits	Free or very low-cost home energy audits to determine existence and location of home energy leaks
Budget counseling	Counseling by utility personnel to payment-troubled customers to assist in the reduction or elimination of payment problems through the teaching of money management skills
·eferral	Referral of payment-troubled customers to utility and commun sponsored assistance programs

·rce U S Department of Health and Human Services, *LIHEAP [Low-Income ·me Energy Assistance Program] Report to Congress for Fiscal Year 1990* Vashington, DC U S Department of Health and Human Services, 1991), 145

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CHAPTER TWO

DISCONNECTION MORATORIA AND RESTRICTION POLICIES

During the late 1970s and early 1980s, many electric and gas service residential customers faced a dilemma due to the relative increase in the costs of electric and gas utility service compared to their increase in income Some have dramatically termed this as the "heat or eat" dilemma [1] In some individual low-income households the problem of having enough money to pay for winter heating (or summer cooling for the elderly or infirm) may indeed actually be a choice between purchasing energy for household heating and purchasing food Other times, the dilemma takes the form of choosing between needed energy and prescription medicine or other necessities The problem is that low-income residential customers, many of whom are the working poor, often face difficult choices, particularly in those areas of the country that are subject to long, hard winters This problem is compounded by the quality of the housing stock available to the poor, typically older housing that lacks weatherization and conservation measures that assure the efficient use of energy The point is that whatever form

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[1] For example, see Steven Deerwester and Marsha Ryan, "Heat or Eat? — Ohio's Percentage of Income Plan," *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, Robert E Burns, ed (Columbus, OH The National Regulatory Research Institute, 1994), 1667 Of course, the problem of poverty is age-old and did not descend on us during the 1980s Rather, it would be better to say that the "heat or eat" dilemma was exacerbated during those years The "heat or eat" dilemma rose to the public agenda as a social problem to be addressed during the 1980s

the so-called "heat or eat" dilemma takes, the financial burden of electric and gas utility service on low-income customers can create social distress

Since the early 1980s, the "heat or eat" dilemma remains as both a real and potential threat to the health and safety of low-income residential households shown in *Energy Policy and the Poor The Association of Income with Consumption*,[2] the total energy use for low-income households can be as much as 20 percent lower than that of the total population average And, this holds for a wide range of fuel sources used for heating, including natural gas, oil, and electricity, and for every state except Alaska (where bills are virtually the same regardless of income level) Considering the poorer housing stock inhabited by low-income households, as well as their more inefficient heating systems, it appears likely that the lower energy usage by low-income families is caused by the tendency of low-income households to live in multi-family dwellings that, even if energy inefficient, have a lower square footage to heat and have fewer exposed surfaces due to the character of multi-unit housing

However, as shown in the 1994 report *On the Brink of Disaster A State-by-State Analysis of Low-Income Natural Gas Winter Heating Bills*,[3] the natural gas winter heating burden for the average low-income customers, defined here as those qualifying for LIHEAP (typically those households that are living at 150 percent of the poverty level or less), is already significant and will become exacerbated if LIHEAP continues to be cutback or is eliminated [4] An energy burden is defined as the percentage of income burden of a typical winter heating bill for December, January, and February If LIHEAP were eliminated, the natural gas winter heating

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[2] Roger Colton, *Energy and the Poor The Association of Consumption with Income* (Boston National Consumer Law Center, 1990)

[3] Osterberg & Sheehan, *On the Brink of Disaster A State-by-State Analysis of Low-Income Natural Gas Winter Heating Bills* (Scappoose, OR Flying Pencil Publications, 4)

[4] Unless the assistance provided from the LIHEAP program is somehow replaces by other federal or state assistance programs

burden for average low-income customers would increase to 28 2 percent in Connecticut, 25 7 percent in Illinois, 23 4 percent in New York, 23 2 percent in Vermont, and 22 7 percent in Maryland It would remain below 8 percent in only three states Hawaii, Florida, and California, with the energy burden being much worse for those with lower incomes Obviously, without alternatives to utility service disconnection for a failure to pay one's bill, the "heat or eat" dilemma will worsen as LIHEAP cutbacks (referred to in Chapter 1) take effect

However, the problem of utility service disconnection is not new Indeed, as shown in *Homes Without Heat A Nationwide Study of Disconnected Natural Gas Users,* approximately 1 8 million households lost utility service in 1984 In the late 1970s and throughout the 1980s state commissions sought to tackle this problem head-on by developing a number of utility disconnection policies meant to limit the number of utility disconnections, particularly during the winter months State commissions apply several different approaches in their disconnection policies

PRIOR NOTICE

As shown in Figures 2-1 and 2-2, in the thirty-nine (shaded) of forty state jurisdictions responding to the survey, state commissions or their utilities have a policy of providing prior notice before a utility service disconnection There is no real debate on the wisdom of this policy Indeed, the primary variation between state commission policies purports to be whether there are people other than the customer who will also receive a notice prior to a utility service disconnection For example, in some states, social agencies will be notified if a physician certifies that the health of the customer would be jeopardized by a utility service disconnection

WINTER RESTRICTION AND DATE-BASED MORATORIA

As shown in Figures 2-3 and 2-4, state commissions or their utilities in thirty-one of the forty jurisdictions responding to the survey have a policy of winter restriction moratoria For winter restriction moratoria, a utility is prohibited from disconnecting a customer during a set period that coincides with winter These are

Fig 2-1 States in which the state commission or its utilities have a prior notice policy for gas utility service disconnection Source NRRI survey results

Fig 2-2. States in which the state commission or its utilities have a prior notice policy for electric utility service disconnection Source NRRI survey results

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Fig 2-3 States in which the state commission or its utilities have a winter restriction gas disconnection moratorium policy Source NRRI survey results

Fig 2-4 States in which the state commission or its utilities have a winter restriction electric disconnection moratorium policy Source NRRI survey results

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typically date-based moratoria States in which the state commission or its utilities have a date-based restriction gas disconnection moratorium policy are shown in Figures 2-5 and 2-6

Winter moratoria on utility bills are an attempt by state legislatures and/or public utility commissions to address a fundamental issue in our society the availability from regulated utilities of energy for heating for low-income customers These moratoria began with the first winter moratorium, which was instituted by the Wisconsin Public Service Commission in the winter of 1973-1974 The winter moratoria spread as a result of the section 115(b)(4) and 303(b)(1) standards of the Public Utility Regulatory Policies Act of 1978 (PURPA) They provided that a state commission should consider and determine whether a moratoria on electric and gas service disconnection during a period when a disconnection to a customer would be especially dangerous to the health of the customer and the consumer established an inability to pay for the service, except in installments, served the purposes of PURPA Although it was not mandatory for the state commissions to adopt the PURPA standard, it did focus state commission attention on service disconnection and winter moratoria As a result by late 1985, over half the state commission (including the District of Columbia) had winter utility service moratoria in place [5]

Although widespread, there are some potential problems with winter restriction moratoria For example, winter restriction moratoria are subject to free-rider abuse In particular, because date-based winter moratoria are predictable, they can be subject to abusive strategic behavior by free-riders Winter restriction moratoria merely postpone service disconnections They do not lend themselves to

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[5] For early discussions of winter moratoria see, Richard Norgaard and Isabel Jensen, "Winter Moratoriums on Utility Bills" *Public Utility Fortnightly* (December 12, 1985), Kathleen Wanda, "Washington's 1985 Moratorium Program," *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, Robert E Burns, ed (Columbus, OH The National Regulatory Research Institute, 1994), 1625

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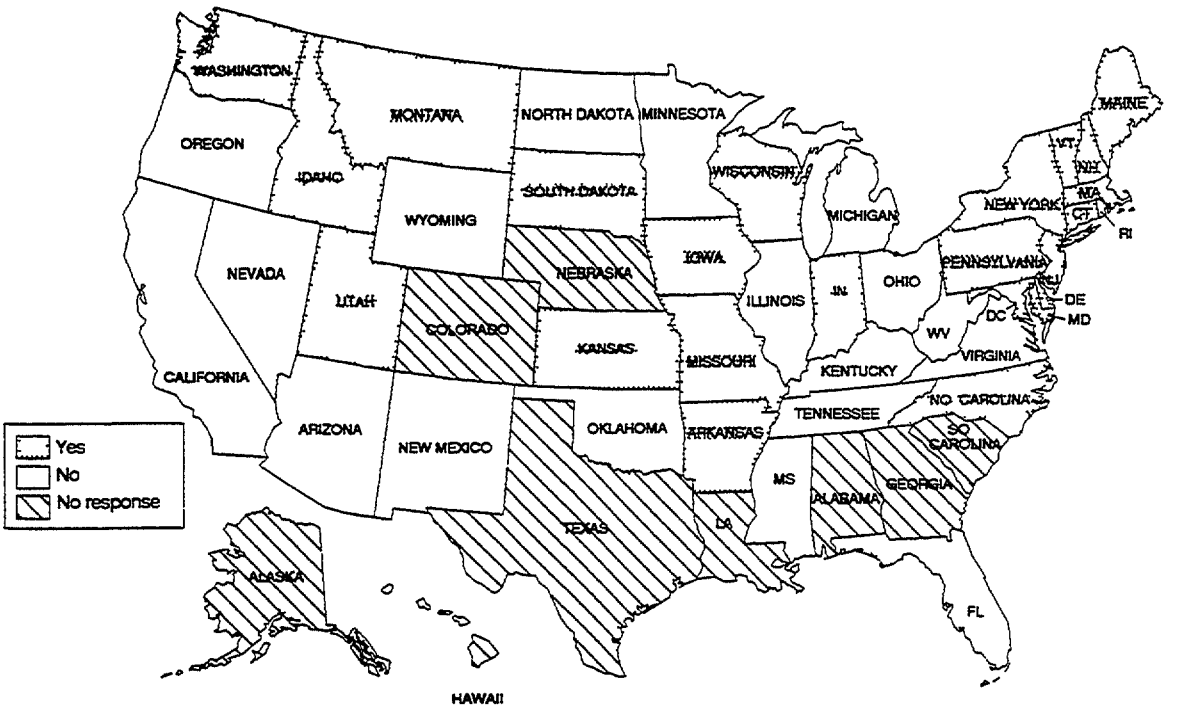

Fig 2 5 States in which the state commission or its utilities have a date-based restriction gas disconnection moratorium policy Source NRRI survey results

Fig 2 6 States in which the state commission or its utilities have a date-based restriction electric disconnection moratorium policy Source NRRI survey results

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a long-run solution Without other programs, one would expect winter moratoria to allow low-income customers to continue to take service without paying the full cost of the service, increasing arrearage, and ultimately bad debt Winter restriction moratoria do nothing to improve consumer usage patterns They are non-educational and do not improve conservation or efficient behavior, and might in fact discourage budget counseling Finally, because date-based, winter restriction moratoria are not directly tied to weather patterns, they are not closely related to actual need

However, dealing with free rider abuse is merely a screening problem This can be addressed through a tight qualification process Winter moratoria could be connected or tied to budget counseling, budget billing, and/or referral services

On the other side, winter restriction moratoria can be argued to provide immediate help and a short-term solution that is essential They are administratively easy and inexpensive to implement for both the utility and the commission They are extremely effective in minimizing social distress, that is, the adverse effects to society of a threat to consumer health and safety And, winter restriction moratoria place a limit on the implicit subsidy that low-income customers receive When the moratorium is over, service disconnections operate to cut off the subsidy, thus limiting the burden on the utility and/or remaining customers

TEMPERATURE-BASED MORATORIA

As shown in Figures 2-7 and 2-8, temperature-based moratoria are used in sixteen out of forty jurisdictions as an alternative to disconnection of electric service and in fifteen out of forty jurisdictions as an alternative to disconnection of gas service The primary difference between temperature-based moratoria and other date-based moratoria is that temperature-based moratoria allow for utility service disconnection when the weather either is above a certain temperature or is forecasted to remain above a certain temperature

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Fig 2-7 States in which the state commission or its utilities have a temperature-based restriction gas disconnection moratorium policy
Source NRRI survey results

Fig 2 8 States in which the state commission or its utilities have a temperature-based restriction electric disconnection moratorium policy
Source NRRI survey results

Most of the pros for implementing temperature-based moratoria are the same as the advantages of keeping date-based, winter moratoria restrictions, that is it is a short-term solution that minimizes social distress However, it can be argued that temperature-based moratoria are more effective than winter-restriction or date-based moratoria An additional pro favoring temperature-based moratoria is that it is less subject to free-rider problems because a temperature-based moratoria is more random, that is, customers cannot plan to abuse it Temperature-based moratoria are also better targeted toward actual need And, temperature-based moratoria could arguably result in smaller arrearage and bad debt than winter- or date-based moratoria

However, temperature-based moratoria are administratively more expensive and difficult to implement Temperature-based moratoria may not minimize social distress if disconnection actually increases, instead, they may increase the number of disconnections around the threshold trigger temperature Further, temperature-based moratoria do not consider differences in housing quality Because of the varied quality and age of housing, some houses are more poorly designed and less energy efficient than others (And, lower-income customers often live in poorer quality, inexpensive housing) Just as with date-based moratoria, it can be argued that temperature-based moratoria are not a long-term solution

DISCONNECTS REQUIRE PRIOR COMMISSION APPROVAL

As shown in Figures 2-9 and 2-10, in eight out of thirty-eight jurisdictions, public service commissions require commission prior approval before service disconnection takes place But requiring commission prior approval is not an outright prohibition against disconnection Rather, commission approval is required prior to a disconnection taking place

Several arguments can be made for requiring commission prior approval before allowing a utility service disconnection First, commission prior approval acts as a double-check that minimizes mistakes and assures that social distress

Fig 2-9 States in which the state commission or its utilities require PSC approval prior to gas utility service disconnection Source NRRI survey results

Fig 2 10 States in which the state commission or its utilities require PSC approval prior to electric utility service disconnection Source NRRI survey results

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costs are minimized Direct commission oversight assures compliance with commission disconnection policies Second, direct commission oversight results in a desirable shared responsibility, which assures the public that social distress costs are properly weighed and considered, and the resulting private-public decision leads to socially preferred actions Further, it allows the consumer to dispute the disconnection, providing them with due process rights for an essential service This provides an implicit stay to disconnection This allows the commission to attempt to find other alternatives to disconnect through an alternative dispute resolution process mediation, conciliation, or facilitation Alternatively, commission prior approval allows the commission to screen people to determine which nonprice social service programs are appropriate and then to make appropriate referral

However, most commissions already preform a double-check on the utility and assure that the utility complies with commission disconnection policies, but do so ex post Further, requiring commission approval prior to service disconnections uses up resources of both the commission and the utility This may be particularly true for high population areas Indeed, commission prior approval may merely delay dealing with the problem of payment arrearage and potential service disconnection and may also "politicize" the process

SERVICE LIMITERS

As shown in Figures 2-11 and 2-12, fourteen of thirty-nine jurisdictions have service limiters as an alternative to electric service disconnection Only one of forty jurisdictions uses service limiters as an alternative to gas service disconnection

An argument can be made that service limiters should be used as an alternative to disconnection First, they implicitly reward payers, allowing payers full service while non-payers receive more restricted service Second, they provide two levels of quality of service, allowing consumer choice and sorting They

Fig 2 11 States in which the state commission or its utilities have a gas service limiter policy Source NRRI survey results

Fig 2 12 States in which the state commission or its utilities have an electricity service limiter policy Source NRRI survey results

diversify product line accor g to the quality of service This makes service limiters similar to interruptible and curtailable service contracts A similar approach could make implementation of service limiters easy [6] Service limiters can modify customer behavior, forcing customers to conserve and make trade-offs in (prioritizes) usage They would be particularly useful for customers who car ay, because it would alter their own priorities, eliminating a moral hazard that there is no penalty for a failure to pay They also force those who can pay to self-budget

Service limiters can act as a companion to (can be tied to) or can increase the voluntary participation in other programs, such as budget billing, weatherization, and/or conservation loans They are compatible with nonprice social service programs, and, while the implementation cost of administering service limiters should be lower, the effectiveness should be higher, there should be less social distress, particularly if service limiters are combined with other programs such as weatherization and conservation Further, service limiters could lower overall system costs through load management by lowering peak usage

Service limiters could arguably be a substitute for a moratorium that could be used year-round In theory at least, service limiters should reduce usage by the poor and hence reduce arrearage and bad debt And, service limiters should increase voluntary participation in other alternative nonprice social service programs, because customers will seek out ways to avoid a lower quality of service Finally, service limiters share the burden more responsibly between the poor and others assuming that the cost of implem ng service limiters is low

However, service limiters put an upper limit on the flow of energy, which might not be sensitive to actual health and safety needs that vary with weather, particularly for gas usage Service limiters have higher up-front costs Moreover, service limiters could penalize those in poorly-designed, energy-leaking homes,

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[6] Hun-Po Chao et al , "Priority Service Unbundling the Quality Attributes of Electric Power," Report EA-4851 (Palo Alto, CA Electric Power Research Institute (EPRI), 1986), and Hun-Po Chao et al , "Service Design in the Electric Power Industry," Report P-6543 (Palo Alto, CA EPRI, 1990)

because the service limiter is likely to be set on the needs and the energy usage of average homes Service limiters need to be combined with weatherization, conservation loans, and targeted conservation for poorly-designed, energy-inefficient housing Otherwise, service limiters could lead to inefficient conservation and weatherization Therefore, a service limiter, unless combined with targeted conservation or weatherization, might penalize those customers with the greatest need who are least able to help themselves

CHAPTER THREE

BILLING AND PRICING ARRANGEMENTS

Changing billing or pricing arrangements so that the possibility of utility service disconnection is less likely is another set of policies that utilities or state commissions can implement to help mitigate the problem of utility service disconnection Although these policies do not directly address service disconnection as did the disconnection policies discussed in the last chapter, they are nonetheless valuable tools that can go a long way toward avoiding utility service disconnection problems One can think of billing or pricing arrangements as a form of financial assistance provided by the utility (and to the extent that the utility is made whole, funded by the ratepayer) that is either reflected in the price charged to the customer or in the customer's bill This category does not include direct financial assistance, such as LIHEAP or fuel funds This chapter discusses partial payment approaches, income-based billing approaches (which include percentage-of-income billing), budget billing, deferred billing, arrearage forgiveness, and lifeline rates

PARTIAL PAYMENT

Partial payment allows a customer to continue to have utility service if some preset minimal partial payment is made on his or her utility bill As shown in Figure 3-1, partial payment is an alternative to electric service disconnection in thirty-two out of forty jurisdictions It is an alternative to gas service disconnection in thirty-one out of forty jurisdictions, as shown in Figure 3-2

Fig 3-1 States in which the state commission or its gas utilities provide for partial payment in lieu of disconnection Source NRRI survey results

Fig 3-2 States in which the state commission or its electric utilities provide for partial payment in lieu of disconnection Source NRRI survey results

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Although it is a widespread policy, one can argue that partial payment should be eliminated as an alternative to disconnection for several reasons First, a potential free-rider (abuser) problem exists Further, because partial payment policies are never used in isolation, their compatibility with other programs is of some concern Partial payments lessen the incentive to conserve or weatherize It lessens the incentive to behave efficiently Partial payments also might increase arrearage and bad debt problems, in part because it offers *de facto* forgiveness by taking away the adverse consequences of not making a full payment Second, partial payments might tend to undermine lifeline rates in those states with that policy, because with lifeline rates the rates increase with increased usage in order to control usage Partial maximum payments dampen these price signals Although it can also be argued that by definition core inelastic customers have very little discretionary income or energy usage so that getting the price signals right should not be that great a concern Third, partial payments might undermine income-based billing programs, because income-based billing is based on an objective notion that equity requires the poor to pay according to their ability to pay Partial payment is based on the subjective notion of the individual customer's need and runs counter to this notion of equity Fourth, partial payments might undermine budget billing, because budget billing is based on making monthly payments that are based on the expected average of the next twelve months usage Partial payments might undercut this payment schedule Partial payments might undermine budget counseling, because partial payments would discourage voluntary participation in budget counseling, and because partial payment undermines the fiscal responsibility that budget counseling attempts to engender

Yet, acceptance of a partial payment might be used as a signal or identifier for other programs The first sign of financial distress might be a missed or partial payment on a utility bill Permitting a partial payment, without actively encouraging partial payments, might serve to minimize a customer's financial distress while signalling to the utility and/or commission that early intervention is needed to refer the customer to the appropriate nonprice social service programs Further, partial payment programs might be formally linked to targeted

conservation, weatherization, energy audits, and budget counseling to encourage their use

Also, it can be argued that allowing partial payments in lieu of service disconnection is socially responsive because such an arrangement (although it may cause a moral hazard problem) provides flexibility for low-income consumers to adjust to income and expense variations This practice helps to create and preserve good will between the utility, the public, and the state commission Also, it can be argued that allowing partial payments minimizes arrearage and disconnections (Collecting something is better than collecting nothing) Accepting partial payments in lieu of disconnection is self-implementing and requires little or no additional commission or utility resources Finally, having a policy of accepting partial payments is socially responsible because it provides short-term help to the destitute, the truly poor, thereby reducing social distress Although, again, it may be a *de facto* arrearage forgiveness

INCOME-BASED BILLING

Income-based payment plans (such as percentage-of-income plans, percentage-of-bill plans, and related programs) require qualifying customers to pay only a portion of their utility bill to avoid disconnection Utilities can use a variety of methods to provide such discounts to their customers in need Unlike general increasing-block rate structures, reduced payment plans are always targeted to customers in need based on affordability However, these programs can vary in terms of providing customers price signals and incentives For example, a simple percentage-of-income payment does not vary with usage, while a percentage-of-bill payment does vary according to usage (even though income criteria are used to qualify participants) Some variations of income-based payment plans also make use of a maximum-bill amount

As shown in Figures 3-3 and 3-4, income-based billing is used in seven out of forty jurisdictions as an alternative to both electric and gas service disconnection Income-based billing plans have a variety of names, the most

Fig 3-3 States in which the state commission or its gas utilities provide income-based billing Source NRRI survey results

Fig 3-4 States in which the state commission or its electric utilities provide income-based billing Source NRRI survey results

common of which is the percentage of income payment plan (PIP) The first income-based billing was the PIP plan put into effect by the Ohio Public Utilities Commission in the winter of 1984 The PIP plan was considered preferable to general disconnection moratoria because it was limited to those at or below 150 percent of the federal poverty level, and it required those who are eligible to pay a percentage of their income toward utility services Only people with no income were not required to pay In a 1985 study commissioned by the Ohio Public Utilities Commission, a consultant found that the PIP customer is typically older, not employed, and generally renting his or her dwelling, the PIP customer consumes more gas, but the same amount of electricity as a non-PIP customer, the PIP customer has less insulation in his or her dwelling and that three of four PIP customers will not be able to pay off arrears by maintaining percentage of income payments through the non-heating period (although a small number of high usage customers might be causing this result)[1]

It is noteworthy that income-based billing, and in particularly PIP plan approaches, have strong advocates, who point out that if PIP were combined with LIHEAP payments then a balance can be struck between the desire not to increase the utility's arrearage and not disconnect low-income customers PIP plans would have the desirable effect of having low-income customers pay what they could afford [2] And, one case study shows that PIP plans have been successful in

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[1] Steven Deerwester and Marsha Ryan, "Heat or Eat -- Ohio's Percentage of Income Plan," Tracell Inc , *A Study of the Results of the Commission's Procedural Determination of Customer Payment Options Pursuant to the Investigation into the Long-Term Solutions Concerning Disconnect of Gas and Electric Service in Winter Emergencies* (1985)

[2] Roger Colton, "Percentage of Income Payment Plans As An Alternative Distribution of LIHEAP Benefits Good Business, Good Government, Good Social Policy" (Boston National Consumer Law Center, 1991), and Roger Colton, "Evaluation of Warwick (Rhode Island) Percentage of Income Payment Plan (PIPP) Demonstration Project" (Boston National Consumer Law Center, 1988)

reducing the number of disconnections over time for those customers covered by a PIP plan [3]

There are several arguments in favor of income-based billing First, income-based billing may be considered more equitable, because it ties financial assistance to ability-to-pay, typically measured by a percentage of income Also, income-based billing may be considered more equitable because it is not influenced by exogenous factors beyond the customer's control, such as rate increases or weather changes It can be argued that income-based billing induces better customer payment behavior compared to discounted or lifeline rates, because it is tied to the customer's ability to pay Second, targeting customers for income-based billing should be easier Customer income should be obtainable from social service agencies Third, income-based billing mimics partial payment and budget billing by laying out clear expectations for a customer's payment obligations Income-based billing mimics budget billing, by producing more levelized payments if income is not highly variable Income-based billing thus combines concepts of partial payment and budget billing, and constitutes an effective substitute for ther Fourth, some claim it is anti-cyclical and helps the poor during a recession [4]

On the other hand, one might argue that income-based billing should not be adopted because it is less efficient than billing customers for the full cost of service Some argue that individual consumption behavior is not affected For income-based billing customers who face a marginal price of zero, with no billing effect of increasing marginal usage, there may be a tendency to waste There is also no incentive to weatherize or to voluntarily conserve However, proponents of PIP plans dismiss this argument as one of "blackboard economics" that has

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[3] See Roger Colton, "Ohio's Percentage of Income Plan Problems and Potentials (A Response to CG&E's Donald Marshall) (Boston National Consumer Law Center, 1991)

[4] Ashley C Brown, "Percentage of Income Payment Plans Regulation Meets Social Policy," *Public Utilities Fortnightly* (March 19, 1987), 9-12

insufficient foundation for several reasons low-income households' demand for energy is relatively price inelastic and therefore does not respond to price signals, low-income households rarely pay their entire bill, and budget billing makes price signals irrelevant [5] While the first concern that low-income households' demand is relatively price inelastic is significant, the argument that income-based billing is less efficient than billing based on the full cost of service is hard to refute

Second, there is a moral hazard problem, customers may misrepresent this income status to receive lower-cost service This can particularly be a problem where income earned in the cash (underground) economy is unreported or underreported Also, customers may sign up for the program when they have a transitional loss of income and may not leave after the transitional loss period is over Third, because it is anti-cyclical, it may burden the utility the most during a recession when revenues may already be down It may also burden other ratepayers who pay an implicit subsidy to support the program Fourth, some argue that income-based billing can be administratively-expensive because customer income can be variable, which is particularly true for the destitute Fifth, income-based billing can cause cross-subsidies either between customer classes or within the residential customer class, with the burden of low-income customers shifting to other residential customers Such cross-subsidies are not sustainable over the long run in more competitive environments

BUDGET BILLING

As shown in Figures 3-5 and 3-6, budget billing is used in thirty-four out of forty jurisdictions as an alternative to gas and electric service disconnection

Budget billing plans are used to spread payments evenly over the year, so that higher seasonal costs for winter heating or summer cooling do not disrupt

[5] Colton, "Percentage of Income Payment Plans As An Alternative Distribution of LIHEAP Benefits," 44-45

Fig 3 5 States in which the state commission or its gas utilities provide budget billing Source NRRI survey results

Fig 3-6 States in which the state commission or its electric utilities provide buc et billing Source NRRI survey results

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customer budgets Budget billing makes it easier for customers to budget their monthly utility payments Nearly everyone agrees that budget billing is good public policy that levelizes bill levels, minimizes bill shock, and hence minimize the number of utility service disconnections Specifically, budget billing smooths out variations in weather over time, reducing transitory disconnections Further, because low-income residential customers are relatively inelastic, there is no significant loss of consumption efficiency [6]

Budget billing is also a desirable program because if has no moral hazard problem Further, budget billing compliments other nonprice social service programs, particularly conservation and weatherization Budget billing helps to teach socially responsible planning and budgeting by allowing customers to know and budget their energy consumption in a monthly bill Without budget billing, utility service bills during unusually cold or hot months become a major source of social distress

The only down-side argument that can be made against budget billing is an economic one it might mute price signals sent by seasonal, time-of-use, time-of-day, or real time pricing rates [7] However, as mentioned, low-income residential customers' demand for energy is relatively price inelastic and would not respond well to these price signals Few, if any, low-income residential customers are subject to such rate schedules

DEFERRED BILLING

As shown in Figures 3-7 and 3-8, deferred billing is used in thirty-five out of forty jurisdictions as an alternative to electric service disconnection and in thirty-four out of forty jurisdictions as an alternative to gas service disconnection

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[6] See Michael Hennessy, " The Evaluation of Lifeline Electricity Rates Methods and Myths," *Evaluation Review* 8, no 3 (June 1984), 327-46

[7] This criticism can be found in Karl McDermott, *Budget Billing Plans for Electric and Gas Utilities An Analysis and Recommendations* (Columbus, OH The National Regulatory Research Institute, 1979)

Fig 3-7 States in which the state commission or its gas utilities provide for deferred billing in lieu of disconnection Source NRRI survey results

Fig 3-8 States which the state commission or its electric utilities provide for deferred bi in lieu of disconnection Source NRRI survey results

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This option is rarely discussed and seems not to be controversial Indeed, allowing customers to arrange a deferred payment plan with the utility to pay bills is a widely accepted option Arguments in favor of deferred billing include that deferred billing is good for those with payment problems because of transitional income Deferred billing creates a self-implementing option that may be preferable to partial payments Income can be used to screen individuals for deferred billing programs in order to minimize any adverse selection problems Budget billing and budget counseling can be made available for those who can pay, and deferred billing can be made available only for those customers with temporary, transitory payment problems Deferred billing can supply useful information for social agency referral and for other available programs, such as conservation and weatherization

While deferred billing may appear to be a substitute for partial payments or budget billing, they may instead be supplementary options, each better suited for different types of customers

ARREARAGE FORGIVENESS

As shown in Figures 3-9 and 3-10, arrearage forgiveness is used in two out of thirty-nine jurisdiction as an alternative to electric service disconnection and in six out of thirty-nine jurisdictions as an alternative to gas service disconnection

Arrearage can be forgiven in various ways Many utilities will provide one-time bill forgiveness to customers in a temporary crisis Arrearage forgiveness might depend on customer participation in educational and conservation programs Special arrangements may be necessary to address arrearage for multifamily dwellings that may be especially suitable for conservation retrofits Partial forgiveness can include waivers of late charges or payment matching by the utility Under a matching program, customers pay portions of their arrears over time while the utility forgives a matching amount Thus, arrearage forgiveness can be an incentive for improvement in bill-payment behavior

Fig 3 9 States in which the state commission or its gas utilities provide for arrearage forgiveness as an alternative to disconnection Source NRRI survey results

Fig 3-10 States in which the state commission or its electric utilities provide for arrearage forgiveness as an alternative to disconnection Source NRRI survey results

Arrearage forgiveness programs are not widely used, they would appear to make little sense unless linked to other options, such as partial payment, income-based billing, budget-billing weatherization, energy audits, budget counseling, referral service, and/or targeted conservation

Those states with partial payment or income-based billing policies may have *de facto* arrearage forgiveness Arrearage forgiveness itself is not automatic On the other hand, arrearage forgiveness can be thought of as merely an extreme form of partial payment where the partial payment is set at zero Therefore, it has advantages and disadvantages similar to partial payment

LIFELINE RATES

Another approach to discounting utility rates is to change the utility's rate structure and provide low-income customers with a more affordable service price for minimum essential use [8] For the purpose of this discussion, the concept of lifeline rates captures the idea of an altered rate structure The use of lifeline rates may or may not be restricted to use by customers with special needs, typically low-income customers A lifeline rate is a type of increasing-block rate that prices a basic block of service at a low rate, while pricing higher consumption blocks at higher rates The basic usage block can be priced below the cost of service (depending on perceptions about the true cost of service) In some conceptions of lifeline rates, the basic usage block would vary according to family size or other special circumstances The merit of this premise is debatable However, if the premise is accepted, a methodology for determining the appropriate basic level of household usage is required This adds substantially to administrative costs and the chances for error or abuse

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[8] For information regarding rate design alternatives, see Janice A Beecher and Patrick C Mann with James R Landers, *Cost Allocation and Rate Design for Water Utilities* (Columbus, OH The National Regulatory Research Institute, 1990)

As shown in Figures 3-11 and 3-12, lifeline rates are used in seven of thirty-nine jurisdictions as an alternative to utility service disconnection

Some arguments in favor of adopting lifeline rates are as follows Lifeline rates can be designed to provide rate relief for low-income customers, to reduce bad debt and arrearage, and to reduce disconnections This assertion can be empirically tested Second, because some minimal usage of gas and/or electricity is an "essential service" that provides "essential human needs" (such as lighting, cooling, refrigeration, water heating, and space heating), lifeline rates provide an initial "lifeline" block of low-cost electricity for low-income customers Third, because low-income customer's essential human needs are price inelastic, lifeline rates do not necessarily lead to consumption inefficiency [9]

The following arguments can be made against the adoption of lifeline rates First, the demands of low-income customers are not totally price inelastic and lifeline rates will lead to some foregone efficient consumer behavior In other words, lifeline rates weaken whatever incentives there are to engage in efficient conservation and energy usage Sometimes lifeline rates are not targeted for the poor, with the result that middle- and upper-class low-usage customers who can afford to pay the cost of gas or electricity are effectively subsidized by high-usage, low-income customers who cannot Because many of the working poor, poor seniors, and destitute are master metered and have their utility bills included in their rent, lifeline rates may be ineffective in guaranteeing them low-cost energy for essential service needs Targeted lifeline rates for low-income customers are discriminatory and could conceivably be argued to be undue price discrimination Finally, because lifeline rates are not tied to the customer's ability to pay, they are less likely to result in better customer payment behavior than income-based billing

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[9] Michael Hennessy, "The Evaluation of Lifeline Electricity Rates Methods and Myths," *Evaluation Review*, Vol 8, No 3 (June 1984), 327-346

Fig 3-11 States in which the state commission or its gas utilities have a policy that provides for gas lifeline rates Source NRRI survey results

Fig 3-12 States in which the state commission or its electric utilities have a policy that provides for electric lifeline rates Source NRRI survey results

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CHAPTER FOUR

NONPRICE, PREVENTIVE, CUSTOMER SERVICE PROGRAMS

A variety of nonprice, preventive, customer service programs can also serve as alternatives to utility service disconnection by lowering energy usage through conservation loans, weatherization, energy audits, or targeted conservation, by providing budget counseling, by providing social service referrals, or by providing financial assistance Each of these nonprice, customer service programs seeks to prevent service disconnection from arising

CONSERVATION LOANS

As shown in Figures 4-1 and 4-2, conservation loans are used in five of thirty-nine jurisdictions as an alternative to electric service disconnection and are used in four of thirty-nine jurisdictions as an alternative to gas service disconnection

A major problem with conservation loans is that they typically have low participation rates The extremely poor (the destitute) typically do not find them useful They nevertheless might be useful to the working poor and the elderly who are on fixed incomes [1]

[1] Paul Stern et al , "The Effectiveness of Incentives for Residential Energy Conservation," *Evaluation Review* 10, no 2 (April 1985) 147-76

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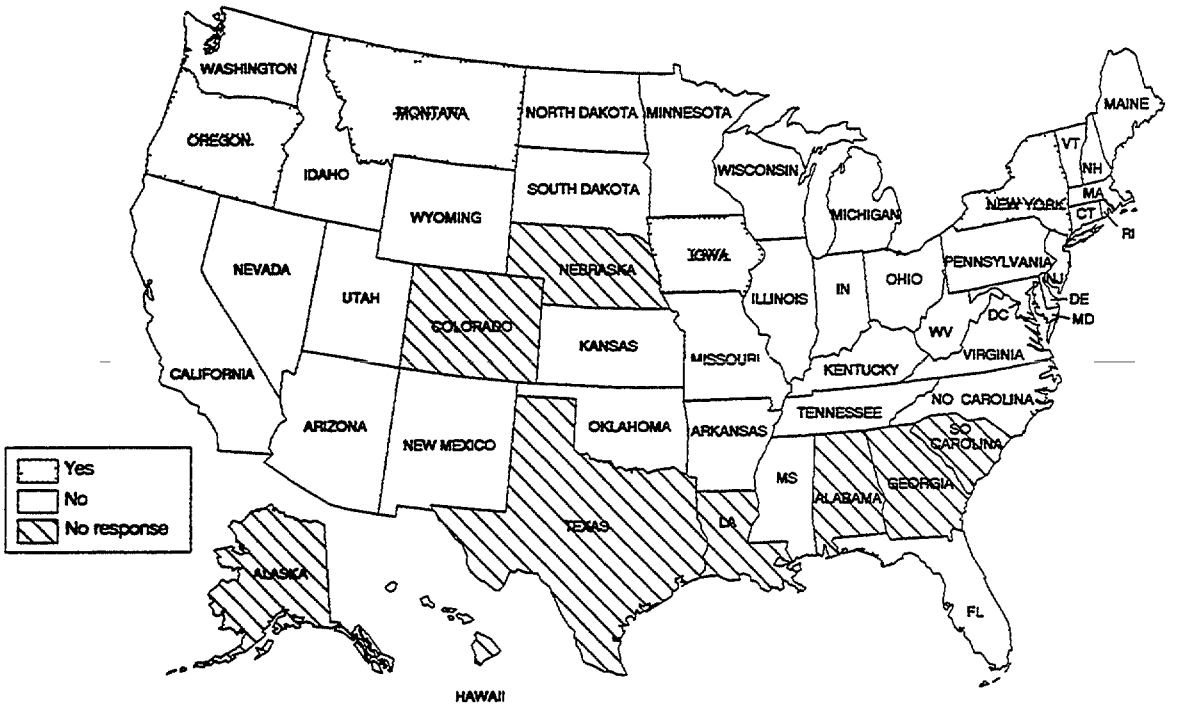

Fig 4-1 States in which the state commission or its gas utilities have a policy that provides for gas conservation loans Source NRRI survey results

Fig 4-2. States in which the state commission or its electric utilities have a policy that provides for electric conservation loans Source NRRI survey results

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Conservation loans are often coupled with weatherization and targeted conservation for both electric and gas utility service This seems sensible, particularly for the working poor and seniors who are not destitute By providing conservation loans, utilities avoid free rider problems and provide an incentive to invest in cost effective conservation and weatherization, since the source of the loan payback would be the increased cash flow that results from lower energy bills Alternately, conservation loan payback could be set at split-the-energy-savings to guarantee that the conservation loan is invested effectively

WEATHERIZATION

As shown in Figures 4-3 and 4-4, weatherization is used as an alternative to electric service disconnection in seventeen out of thirty-nine jurisdictions and used as an alternative to gas service disconnection in eighteen out of thirty-nine jurisdictions

An argument can be made that the adoption of weatherization as an alternative to service disconnection should be encouraged Weatherization is environmentally sound because it reduces fossil fuel use Weatherization promotes efficient household use of energy, optimizes household use of resources, and (with or without a "snap-back effect") results in a higher quality of life [2] Weatherization is also a long-term solution, if done correctly Further, because weatherization

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[2] A "snap-back effect" occurs when a customer consumes more in response to a lower marginal cost One might expect a customer to be willing to consume more energy service (e g , more cooling or space heating) if the marginal cost of the energy is lowered due to weatherization See Kenneth Costello, "Ten Myths of Energy Conservation," *Public Utilities Fortnightly* (March 17, 1987), 19-22

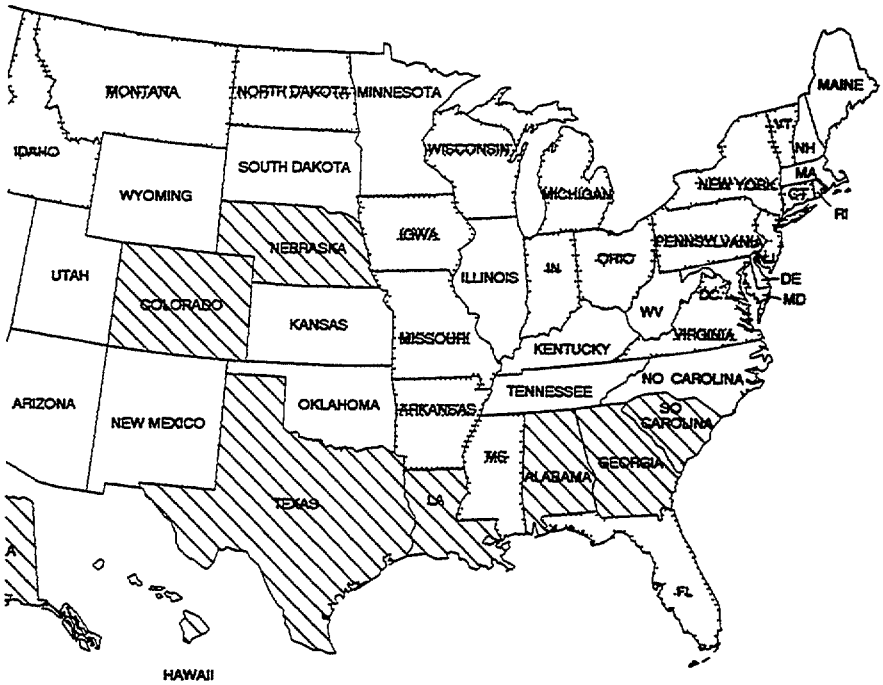

Fig 4-3 States in which the state commission or its gas utilities have a policy that provides for weatherization Source NRRI survey results

Fig 4-4 States in which the state commission or its electric utilities have a policy that provides for weatherization Source NRRI survey results

reduces energy usage,[3] it should lower arrearage and lead to fewer disconnections Weatherization is incentive compatible,[4] because it lowers bills and helps participants by increasing property values

Weatherization does not help the destitute (hard-core, renting poor), particularly since many of these are tenants with landlords that may be unwilling to par' ipate If landlords take part, there is a free-rider problem with landlords effec vely receiving a subsidy of increased property and rental value [5] Also, it can be argued that weatherization is subject to a public-private problem, that is, a public investment is used to try to solve a private problem Although, others may ar that, if the public benefit from weatherization exceeds the costs, one should nc e overly concerned about the blic-private problem

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[3] Peabody, G A , "Weatherization Program Evaluation," (Washington, D C Energy Information Administration, Office of Energy Markets and Land Use, U S Department of Energy, 1984), Marilyn Brown et al , "National Impacts of the Weatherization Assistance Program in Single-Family and Small Multi-Family Dwellings" (Oak Ridge, TN Oak Ridge National Labs, U S Department of Energy, May 1993), 10 18 As previously noted, the Oak Ridge study used a cost-benefit analysis to show program effectiveness The authors found a program benefit-cost ratio (defined as energy-savings benefits measured against total weatherization costs) of 1 09 However, an issue can be raised whether using an average cost of $6 89 per MBtu (the equivalent of a $39 99 barrel of imported oil) has the appropriate cost to impute the benefits of weatherization, when the average retail price of natural gas was $5 90 per MBtu and the average retail cost of electricity was $ 07 per kWh Using the actual cost of actual avoided re ources would have produced more accurate measurement of the benefits of weatherization

[4] Incentive compatibility is an economic concept that solves the principal-agent problem By creating the proper incentives, the interests of the principal and agent are properly aligned In this case, the ratepayer who weatherizes helps himself, the utility, and his fellow ratepayers

[5] Paul Stern et al , "The Effectiveness of Incentives for Residential Energy Conservation," *Evaluation Review* 10, no 2 (April 1985) The authors list several reasons for homeowners not investing in energy efficiency lack of accurate information, consumer confusion, restricted choice due to previous decisions by appliance manufacturers, as well as not having the time and effort needed to properly invest

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Weatherization can be very expensive, particularly if it is done well [6] For weatherization to be effective it is not enough to weatherstrip and insulate a home To effectively weatherize, one must find and correct all sources of infiltration and energy loss This would require the use of a rigorous test, such as a pressurized blower test, and then customized solutions to the energy loss problems of each home To make cost-effective decisions about weatherization, a neutral objective party must do a sophisticated cost-benefit analysis Opponents of weatherization contend that this is not to be done Moreover, it is at least arguable that job creation should not be a consideration in such a cost-benefit analysis because the money spent on weatherization could have been spent elsewhere in the economy also creating jobs [7] At best weatherization is most properly a long-term solution that lessens the possibility of disconnection for those participating in the program but that does not solve the immediate short-term problem of the larger population

ENERGY AUDITS

As shown in Figures 4-5 and 4-6, energy audits are used in twenty-nine out of forty jurisdictions to help prevent electric service disconnection and in twenty-five out of forty jurisdictions to help prevent gas service disconnection

One might argue that energy audits are ineffective and should not be used In the past, energy audits were imprecise measures that overestimate potential energy savings The reason that some simplified energy audits overestimate

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[6] For example, an Indiana CAP Director Association stated that its on-site weatherization testing and installation costs averaged $1,250 per household According to Brown et al , *National Impacts of the Weatherization Assistance Program* (1989) the program-wide average total installation cost per dwelling for weatherization was $1,050 with an average additional $500 per dwelling in overhead and management costs This brings the average 1989 cost of weatherizing a dwelling to $1,550

[7] For example, the inclusion of employment, environmental externality and other nonenergy benefits increases the program benefit-cost ratio of 1 09 to 1 to a societal benefit-cost ratio of 1 72 to 1 Ibid

Fig 4-5 States in [illegible]h the state commission or its gas utilities have a policy that provides for gas energy audits Source NRRI survey results

Fig 4-6 States in which the state commission or its electric utilities have a policy that provides for electric energy audits Source NRRI survey results

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potential energy savings is that they cannot capture all sources of energy loss Energy audits can be expensive, especially if they are thorough Energy audits are not a stand-alone activity They only make sense if combined with targeted conservation and/or weatherization And, finally energy audits have lower voluntary participation rates, particularly among the destitute (the poorest customers who cannot pay and who are typically not homeowners) Unless it is a voluntary, simplified energy audit, it is also an intrusive process

Supporters of energy audits contend that energy audits are fairly simple and not very involved They are less intrusive and less expensive than the data collection necessary for Home Energy Rating Systems Energy audits, although imprecise, can still "ballpark" the potential energy savings Energy audits help to determine the severity of the problem By conducting energy audits, weatherization and low-income conservation programs can be targeted so that they can be cost effective and efficient Finally, proponents argue that energy audits do tend to result in energy savings, and that inexpensive energy audits produce as much energy savings as more expensive energy audits [8] Energy audits tend to help homeowners, which tend to include be poor seniors and the working poor

BUDGET COUNSELING

As shown in Figures 4-7 and 4-8, budget counseling is used in thirteen out of thirty-nine jurisdictions as an alternative to electric service disconnection and in twenty-five out of forty jurisdictions as an alternative to gas service disconnection

Utilities can offer some customers nonmonetary assistance in the form of budget counseling to help customers budget for their utility and other costs Counseling may be especially important for customers who must budget on a weekly or monthly basis but pay a quarterly water utility bill Counseling can be

[8] Richard S Ridge, "An Analysis of Various Types of Energy Audits," *Evaluation Review* 10, no 3 (June 1986) 385-95

Fig 4-7 States in which the state commission or its gas utilities have a policy that provides for budget counseling Source NRRI survey results

Fig 4 8 States in which the state commission or its electric utilities have a policy that provides for budget counseling Source NRRI survey results

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used to help utilities convey the importance of timely payments and the potential consequences of nonpayment Counseling also can be used to improve customer understanding of utility bills, increase awareness of methods for controlling costs, and refer customers to available community-assistance programs

It would seem that budget counseling should be more widely adopted Budget counseling is targeted toward consumers who are not destitute Although they should have enough money to pay their utility bills, prioritizing their expenditures is the problem It is often tied to budget billing Budget counseling should lead to fewer and smaller arrearage, because it is an educational solution to the problem Budget counseling provides an opportunity and means to link people up with budget billing and energy audits, where appropriate Budget counseling can act as an early link-up to social referral programs, financial assistance, and other non-price assistance programs By providing an evaluative, diagnostic screen, it can help streamline referral and integrate social services, thus making customer use of social services more efficient

Further, budget counseling may eliminate the need for other less satisfactory pricing and billing arrangements (such as, partial billing, income-based billing, deferred billing, and arrearage forgiveness) Budget counseling minimizes the overall subsidy and frees up funds for the destitute, the truly poor who cannot pay Budget counseling also frees up utility funds for targeted conservation and weatherization

On the other hand, budget counseling has low participation rates, particularly among the destitute It only works well for senior citizens and the working poor Indeed, budget counseling may be ineffective for the truly destitute who cannot pay Budget counseling requires customized assistance and is labor intensive and expensive to implement, particularly if done in person However, it may be cheaper than utility disconnection, which is also labor intensive and expensive Budget counseling may also duplicate other available social services that can be provided more effectively and efficiently by social service agencies

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REFERRAL SERVICES

As shown in Figures 4-9 and 4-10, referral services are used in twenty-two out of forty jurisdictions as an alternative to electric service disconnection and in twenty-three of forty jurisdictions as an alternative to gas service disconnection

Referrals to appropriate agencies can help customers find bill-payment assistance, as well as more general help in managing personal finances Referrals are especially critical in emergencies and cases of extreme hardship It can be argued that there should be an increased usage of referral services Referral services take advantage of the specialized training of social service agencies and personnel Referral services also help to improve communication and efficiency in the delivery of social services It helps to reduce the redundancy of services and their administrative costs This helps to integrate and coordinate social services, reducing "user cycling "

The failure to pay for utility services is often the first signal of a social service need Therefore, a referral service mitigates social distress Referral services allow the utility to identify and to assign, at an early stage, helpful utility and social service programs This mitigates free rider problems Because of better assignment, there is a more efficient use of social service programs Referral services tie user participation to specific utility or social service programs One would expect that early referral services also help to mitigate the problems of service disconnection, arrearage, and bad debt Early referral services help to avoid the need for more drastic, and more expensive subsidy billing and pricing measures

However, referral services may simply be passing the buck, that is, an excuse to remove the utility and the commission from the role of problemsolver Further, referral services may be highly bureaucratic, labor intensive, and expensive While referral services may best serve the destitute individual because the social agencies are designed to serve those individuals, they may not provide early intervention and service for those with less severe problems Because there

Fig 4-9 States in which the state commission or its gas utilities have a policy that provides for referral services Source NRRI survey results

Fig 4-10 States in which the state commission or its electric utilities have a policy that provides for referral services Source NRRI survey results

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is competition for social services, there is selectivity bias, which may or may not be appropriate, to provide the most social services to those with the greatest need This could lead to a misallocation of social service resources There is still a need for other utility programs for customers who are not destitute

TARGETED CONSERVATION

As shown in Figures 4-11 and 4-12, targeted conservation is used in thirteen out of thirty-nine jurisdictions as an alternative to electric service disconnection and in eleven out of thirty-nine jurisdictions as an alternative to gas service disconnection

Given the current federal budgetary policies and efforts to reduce the federal deficit and to slow the growth of the national debt, there is a scarcity of funds available for non-price social assistance programs Efficiency demands that they be better utilized by targeting conservation efforts In targeted conservation programs, the poor are not free riders, assuming that the destitute, receive help first [9] By specifically targeting the poor, it mitigates user abuse and free-riders the most needy are served and the wealthier excluded Because money is targeted, the less needy are pressured to solve their own problems Thus, it mitigates against the use of public funds for improving private property, arguably a private purpose Public funds do not crowd out private funds and initiatives

Alternatively one can argue against targeted conservation By targeting conservation for the poor, the impact may be minimal the poor live in poorly designed housing, which might be the most expensive to rehabilitate Therefore, these expenditures might fail a cost/benefit test in that the marginal cost of the programs might exceed the marginal benefit Unless it is linked (tied) to other

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[9] For an argument that conservation and DSM programs should be specifically targeted for low-income customers see Nancy Brockway, "The Low-Income Customer As A Non-Participant in DSM What Is to Be Done?" (Boston National Consumer Law Center, 1992), 4

Fig 4-11 States in which the state commission or its gas utilities have target gas conservation programs Source NRRI survey results

Fig 4-12 States in which the state commission or its electric utilities have target electric conservation programs Source NRRI survey results

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programs, targeted conservation has low participation rates, particularly among the destitute Targeted conservation is also labor intensive, with high implementation costs Finally, targeted conservation for the poor creates a selectivity bias because a marginal cost/benefit test is not used to allocate resources

Nevertheless, targeted conservation may still cost less than disconnection The selectivity bias also may be appropriate because conservation loans might be a more appropriate alternative for the non-destitute

FINANCIAL ASSISTANCE

Financial assistance looks to the community (as compared to utility resources) for providing assistance to customers in need Generally, it involves community-based nonprofit organizations that use donations to fund bill-payment assistance efforts Financial assistance can be provided through utilities with the use of voluntary programs that rely on customer contributions Often, utilities can make use of nonprofit service organizations for implementing these programs

As shown in Figures 4-13 and 4-14, financial assistance is offered in thirty-three of thirty-nine jurisdictions as an alternative to electric service disconnection and in thirty-four of thirty-nine jurisdictions as an alternative to gas service disconnection (However, we suspect that the number of jurisdictions having financial assistance programs is underreported because sometimes LIHEAP is not reported Public sources are available for LIHEAP in all jurisdictions)

There are basically four groupings of financial assistance loans versus grants, and public versus private sources of funding Loans were previously discussed under the category of conservation loans The following discussion focuses on grants By far the principal (but not only) source of federal funding is LIHEAP funding Through fiscal year 1994, LIHEAP was funded at approximately $2 billion per year for each of the previous ten years, with at least 10 percent of the funds required to be spent on weatherization (Actually, about $300 million

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Fig 4-13 States in which the state commission or its gas utilities have financial assistance programs Source NRRI survey results

Fig 4-14 States in which the state commission or its electric utilities have financial assistance programs Source NRRI survey results

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annually was spent on weatherization in recent years) However, as noted, LIHEAP funding is being severely cut back

Private funding comes from a variety of sources that are pooled into local fuel funds According to the National Fuel Funds Network, private funding provides about $72 million in financial assistance per year Fuel funds are bimodal in their criteria on who receives t funds About half is designed to supplement LIHEAP fu ng, wit remaining half designed to complement LIHEAP funding In other words, about half of the fuel funds go only to those who qualify for LIHEAP funding, and about half go to those who, although poor, do not qualify for LIHEAP funding

One can contend that there should be more in-kind transfers for low-income customers One major area of contention, however, is the loan versus grant debate Loans give the borrower something in return for future performance, which requires greater individual responsibility and performance Loans must be paid back Loan expenditures are usually at the discretion of the borrower, providing the consumer with greater discretion and more degrees of freedom Loans have a fixed time-frame, which can be set to match the loan repayment period to the life-cycle of the investment One can e loan interest rates to performance, making a loan incentive compatible This rewards credit-worthiness (loan repayment) and rewards those who put loaned money to good use On the other hand, loans require a greater investigation into the credit-worthiness of those receiving them

Grants may or may not be tied to making a particular expenditure Grants are not tied to future performance and require no future responsibility Grants are also called in-kind transfers They are usually targeted to something specific, which implies less discretion Grants tend to be more bureaucratic, with more administrative oversight on how the grant will be expended Grants might be more expensive to implement As noted, grants are not tied to future performance, instead grants are tied to current need Grants do not tend to be incentive compa ble There is no incentive to perform well, because there are not penalties

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for taking actions inconsistent with an efficient investment Grants demand more from the grantors since grants are never paid back

Loans are probably a feasible strategy for the working poor and most seniors Loans can easily be tied to budget counseling and budget billing Loans are probably not feasible for more improvident individuals, for whom a loan de facto becomes a grant because it is never paid back Loans are often called a cash transfer Note that split-savings plans to encourage DSM and conservation investment are really types of loans

Business Model

- organization
- process
- planning
- management

CHAPTER 14

Consumer-Owned Utility Systems

SYNOPSIS

§ 14 01 Introduction

§ 14 02 Rural Electric Cooperatives
[1] Regulatory Environment
[a] Accounting
[b] Ratemaking
[c] Capital Expenditures
[2] Organization
[3] Nonprofit Operation
[4] Taxation

§ 14 03 Local Publicly Owned Systems

§ 14 04 Joint Generation

§ 14.01 Introduction

This chapter discusses in general terms some of the accounting and operating characteristics of consumer-owned utilities and contrasts the basic differences between these utilities and their investor-owned counterparts [1] Although there are consumer-owned telephone, gas, and

[1] Various reference materials were used in developing the concepts presented in this chapter See generally the following sources D Allen and W Mayben *Joint Ventures in the Electric Power Industry* (1981) First Boston Corp *Survey of Generation and Transmission Cooperatives* (1979) Rural Electrification Admin, *Uniform System of Accounts* Bulletin 181–1 (1978) and Rural Electrification Admin *1988 Statistical Report Rural Electric Borrowers* REA Bulletin 1–1 (1989)

water and sewerage utilities, for sake of comparison, this discussion focuses mostly on consumer-owned electric utilities The basic differences between consumer- and investor-owned electric utilities also apply to these other utility services

Generally, consumer-owned electric utilities are of two types—rural electric cooperatives and local publicly owned systems The latter type generally includes municipals, public utility districts, state and county systems, and joint action agencies In general, consumer-owned electric utilities are much smaller than investor-owned electric utilities, and although they often generate their own power, they have typically purchased a substantial portion of their needs However, the trend over the past decade has been toward greater self sufficiency in power supply Further, even though consumer-owned companies tend to be smaller than their investor-owned counterparts, because of their large number, they possess a significant share of the U S electric market, as evidenced by the following table [2]

	Consumer-Owned Electric Utilities	Investor-Owned Electric Utilities
Number of systems	2,993	265
Number of customers	24%	76%
KWH generation	25%	75%

There are other significant differences, in addition to size and purchase-generation mix, that distinguish consumer-owned utilities The rest of this chapter is devoted to a brief discussion of these differences Because cooperatives are perhaps a more identifiable segment of the industry, most of the discussion focuses on electric cooperatives

§ 14.02 Rural Electric Cooperatives

A cooperative, as the term suggests, is an organization composed of members who, because of common interests, have joined together to own and operate a business There are basically two types of electric cooperatives the power supply co-op and the distribution co-op Power supply co-ops, also referred to as generation and transmission cooperatives (G&Ts), produce or acquire power for sale to their members, generally distribution co-ops, at wholesale rates Distribution co-ops

[2] American Public Power Assn *Public Power—Directory* (Jan-Feb 1991) Based on 1989 statistical data

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sell power to their members, who are generally individual consumers in rural areas Approximately 1,000 electric cooperatives are in the United States, of which about 60 are G&Ts

To contrast the differences between electric co-ops and other electric utilities, it is helpful to know something of the former's origin, as well as the regulatory environment in which electric co-ops operate For all practical purposes, the origin of electric cooperatives may be traced to the Rural Electrification Act of 1936 [3] Although electric cooperatives predate this act, it served as a catalyst for growth and expansion by making available the capital necessary to fund that growth The express purpose of the act was to bring about rural electrification through low-interest loans The Administrator of the Rural Electrification Administration (REA) was further empowered to make these loans to companies that would carry out this purpose, with preference given to electric cooperatives and other consumer-owned utilities [4] At that time, only about 10 percent of rural America had electric service Today, primarily because of co-op expansion, approximately 99 percent of U S farmers have electric power

In 1973, in response to an attempted termination of the direct loan program, the Rural Electrification Act was amended to give the Administrator of the REA expanded authority to provide financial assistance to borrowers through loan guarantees In so doing, rural electric cooperatives were allowed to borrow from the newly formed Federal Financing Bank (FFB) The FFB has been a significant source of funding to G&Ts in their expansion of generating facilities over the past decade

The 1973 amendments to the Rural Electrification Act also made it clear that Congress was sanctioning an REA administrative practice of requiring borrowers to seek a portion of their funding from nongovernment sources Today, another primary source of nongovernment funding for electric cooperatives is the National Rural Utilities Cooperative Finance Corporation (CFC), which is itself a cooperative bank owned by its member borrowers Other sources of nongovernment financing include the Banks for Cooperatives (also cooperative institutions), pollution control bond financings, and, more recently, leverage lease financings by taxable cooperatives

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[3] USCA § 901 *et seq*

[4] See 7 USCA §§ 904 930 and Ala Power Co v Ala Elec Co-op Inc 249 F Supp 855 (DC Ala 1965) *affd* 394 F2d 672 upholding the preference

The regulatory environment in which electric cooperatives operate is strongly influenced by their nonprofit status and the oversight exercised by the REA The REA, in 1994, changed its name to the Rural Utilities Service (RUS) The Federal Energy Regulatory Commission (FERC) and many of the states do not regulate electric cooperatives for these very reasons And, in those states in which regulation exists, the approach is generally quite different from that applied to other utilities

In summary, aside from some of the more obvious features, such as size and location, four primary characteristics distinguish electric cooperatives.

(1) regulatory environment,

(2) organization,

(3) nonprofit operation, and

(4) taxation

These differences are explored in more detail in the following sections

[1] Regulatory Environment

As discussed above, a cooperative's primary, and for many years only, source of financing was directly through the Rural Utilities Service (RUS) In recent years, co-ops have borrowed through other lenders, such as the Federal Financing Bank (FFB) and the Rural Utilities Cooperative Finance Corporation (CFC) Most of this debt, however, is still guaranteed by the RUS Thus, the RUS is generally acknowledged as the single most important factor in the financial and regulatory affairs of rural electric cooperatives

The RUS, through its mortgage agreements, has the authority to review all major financial activities of cooperative borrowers It is the RUS's general policy that its borrowers are responsible for charging rates that will produce revenues necessary to meet its requirements as a lender, satisfy mortgage provisions, and maintain a satisfactory equity position Thus, the RUS approaches rates as a banker rather than as a regulator The service's authority is contractual in nature It does not have statutory regulatory authority, as do other federal agencies, such as the Federal Energy Regulatory Commission (FERC)

Moreover, in the *Salt River*[5] and *Dairyland*[6] cases in the late 1960s, it was held that electric co-ops were not "public utilities" within the meaning of the Federal Power Act and, therefore, not subject to FERC regulation over rates and service The rationale for those decisions was that since co-ops were subject to the RUS's supervision and because of their nature as consumer-owned entities, Congress intended that they enjoy a freer hand in areas such as rate making

In addition, cooperatives' rates often do not fall within the jurisdiction of state regulatory commissions Approximately, one-half of the states regulate distribution cooperatives, and one-fourth regulate generation and transmission cooperative (G&T) rates Thus, in many instances, rates are established by the cooperative's board of directors, subject only to RUS mortgage covenants, if that agency has guaranteed the cooperative's debt

This general lack of traditional third-party regulation is a significant difference between cooperatives and investor-owned public utilities A question arises, therefore, whether consumers' interests are adequately protected in a cooperative environment without outside regulation This question can perhaps best be answered by pointing out that the RUS, through its mortgage covenants, does exercise considerable oversight in a number of areas, and that a growing number of states exercise various forms of regulatory jurisdiction The most significant of these areas of regulation are

(1) accounting,

(2) rate making, and

(3) capital expenditures

[a] Accounting

Co-ops are required to maintain their accounting records in accordance with the RUS's uniform system of accounts The RUS's uniform system is very similar to that required by the FERC In fact, except for specific instances in which the RUS prescribes other accounting, any changes in the FERC system of accounts are considered changes in the RUS system There are, however, some minor differences in the account names and numbers used by these two systems

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[5] Salt River Project Agricultural Improvement and Power Dist v FPC 391 F2d 470 (DC Cir 1968) *cert denied* 393 US 857

[6] Dairyland Power Co-op 37 FPC 12 (1967)

In general, rural electric cooperatives follow the same basic accounting rules as investor-owned utilities Although the operational differences discussed above, such as nonprofitability and nontaxability, have financial reporting implications, both types of utilities are considered regulated enterprises and, as such, are subject to Financial Accounting Standards Board (FASB) Statement No 71, "Accounting for the Effects of Certain Types of Regulation " (For a detailed discussion of Statement No 71 and other accounting pronouncements dealing with the effects of rate regulation, see Chapter 12)

When FASB Statement No 71 was first drafted, there was some concern whether it should apply to rural electric cooperatives As discussed in § 14 02[1], above, although the rates that some cooperatives charge their customers are subject to third-party regulation, many are not A cooperative's rates are generally set by its own governing board elected from its membership However, in these cases, the board has in essence rate-making authority and functions similar to an independent third-party regulator It is the RUS's position, which is supported by the FASB, that this difference between cooperative utilities and other utilities subject to third-party regulation does not, as a general rule, justify different accounting for otherwise similar entities Accordingly FASB Statement No 71 covers enterprises, including cooperatives, whose rates are established by their own governing board provided that the board is empowered by statute or by contract to establish rates that bind customers Before RUS borrowers implement FASB Statement Nos 71, 90, or 92 accounting they must receive written approval from the RUS

RUS borrowers are required to practice depreciation accounting, and REA Bulletin 183–1, for example, provides ranges of depreciation rates that electric borrowers may use without RUS approval Use of depreciation rates outside of these ranges must be supported by proof that they are reasonable for the property State regulators probably will not question depreciation rates based on RUS guidelines, but they will respond to rates based on depreciation studies in the same manner as they do for an investor-owned utility REA Bulletin 183–1 rates are based on positive net salvage for distribution property, which was a common situation in the 1960s However, that property began to exhibit negative net salvage in the 1970s and, today, it is common for distribution property to exhibit highly negative net salvage Therefore, REA Bulletin 183–1 rates may not be adequate in today's

environment, leading to reserves for accumulated depreciation that are low relative to the depreciable base

A second difficulty can accentuate a low reserve problem REA guidelines published in the 1950s suggested that the current average installed cost be used as the original cost of items retired This procedure assumes that the age of the retired items is the same as the average age of the surviving items Although this assumption may be a reasonable way to simplify bookkeeping, retired property will probably be older than the surviving property, and the original cost of retirements so determined will be too large because of the effects of inflation This situation may cause the average service life implied by the assumed age of retirements to be much less than the life assumed by the rates in REA Bulletin 183–1 Therefore, REA Bulletin 183–1 rates will be too low and will result in a low book reserve position Although the effects of using REA Bulletin 183–1 guidelines have received little attention over the years, their effect on cost of service and depreciation accounting should not be overlooked Cooperatives should consider the effects of using the guidelines over time and the possible need to depart from the guideline approach in determining future depreciation rates and cost of retirement

[b] Ratemaking

Electric cooperatives are basically nonprofit organizations A cooperative, therefore, attempts to set its rates at a level that will cover its cost of service, and generally earns little in the way of operating margins In addition, the RUS standard mortgage imposes the following minimum operating ratios

	Distribution	G&T
Times interest earned ratio (TIER)	1 50	1 00
Debt service coverage (DSC)	1 25	1 00

$$\text{TIER} = \frac{\text{Net Margin} + \text{Interest on Long-Term Debt}}{\text{Interest on Long-Term Debt}}$$

$$\text{DSC} = \frac{\text{Net Margin} + \text{Interest on Long-Term D} \ldots + \text{Depreciation (Amortization)}}{\text{Interest and Principal Repayments on Long-Term Debt}}$$

The tendency in ratemaking for G&T cooperatives is to treat the minimum TIER ratios as standards and not as a floor As a result, G&Ts, which are the most capital-intensive part of the industry, are often highly leveraged with debt

In defense of the low equity ratio rate for G&Ts, it must be noted that electric rates are generally established so that any excess margins are earned by the distribution cooperatives, a fact that has accounting implications on its own For example, in constructing plant facilities, G&Ts generally do not capitalize interest, associated with the use of equity funds, as a cost of construction

Because RUS and CFC loans are made at a single rate to all cooperatives without regard to financial strength, cooperatives may design their rates to produce less equity without adverse consequences as to financing costs However, this arrangement makes the cooperatives very dependent on government-guaranteed debt financing, and, as a rule, cooperatives are more heavily debt financed than their investor-owned counterparts For example, while a typical investor-owned utility may have a debt-to-equity ratio of 60–40, it is not uncommon for a cooperative to have a ratio of 75–25, or higher In fact many G&Ts have a debt-to-equity ratio higher than 90–10, and some have recently found themselves in the untenable position of having negative equity The following chart, based on 1989 financial information, compares debt/equity ratios [7]

	Distribution	G&T (amounts in thousands)	Total
Long-term Debt	$13 627,775	$29 463,790	$43,0 91,565
Equity	9,794,446	628 224	10,422,670
Total	$23 422 221	$3[illegible] [illegible]2,014	$53,514,235
Debt as percentage of total capital	58 2%	[illegible]	80 5%

[7] Based on information contained in the *1989 Statistical Report Rural Electric Borrowers* N-1, above

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The chart above illustrates two important points

(1) a considerable disparity exists between the debt-to-equity ratios of cooperatives and investor-owned utilities, and

(2) a significant difference also exists in equity retained by distribution cooperatives and by G&Ts

The main reasons for these differences are (1) the ratemaking philosophy employed by cooperatives, and (2) RUS mortgage requirements

As discussed in § 14 02[1], above, regulation of cooperatives' rates by third-party regulators, such as state commissions, is limited and primarily involves distribution systems rather than G&Ts However, in the *Arkansas Electric* case,[8] an attempt to have state regulation of wholesale power sales declared unconstitutional was rejected by the U S Supreme Court, which opens the door to increased state regulation

As a general rule, the form of rate regulation (where it occurs) differs from that of investor-owned utilities State commissions are generally not concerned with balancing the interests of consumers with those of investors, because they are one and the same in a cooperative Instead, they generally approach cooperative rate regulation on a TIER basis Since the RUS mortgage sets a minimum TIER level and a cooperative might try to achieve a higher TIER to build equity, state regulation focuses on how high a TIER a cooperative may achieve Thus, state rate regulation of cooperatives is essentially regulation of the level of equity formation

However, a trend developing in some states is to limit regulation of cooperatives by setting a TIER range Under this approach, the cooperative's management has authority to raise or lower rates to build equity without prior approval from the regulator, as long as the margins earned yield a TIER within a preestablished range This approach recognizes that the time and expense associated with rate regulation is often counterproductive where cooperatives are concerned and that a sound equity base is necessary for the financial health of the cooperative

[c] Capital Expenditures

The final area in which the RUS exerts significant oversight is approval of capital expenditures By virtue of its mortgage, the RUS

[8] Arkansas Elec Coop Corp v Arkansas Pub Serv Comm 3 S Ct 1905 (1983)

has the right of final approval of all major financial transactions, such as purchases or construction of equipment and execution of contracts This right applies even in the case of borrowings through other institutions, such as the FFB or CFC, because this debt becomes a part of the master RUS mortgage

Similarly, state commissions often have the authority to approve significant capital expenditures if prior certification is required by state law

Organization

A number of basic organizational differences exist between investor-owned utilities and cooperatives These differences are highlighted by the basic principles under which cooperatives are organized

1) one-person-one-vote

2) operation at cost, and

3) subordination of invested capital in land ownership and control

Although both investor-owned utilities and cooperatives are generally organized as corporations the cooperative is a typical consumer-owned utility Its principal purpose is to provide safe, low-cost, reliable service to its members/consumers whereas an investor-owned utility has the additional objective of earning a fair rate of return for its stockholders A cooperative does not issue shares of stock Its members' equity position in the organization is determined on a pro rata patronage basis That is each member's share in any operating margins or defects is based on that member's level of purchases of electricity

A distribution cooperative for all practical purposes is owned and operated by its members the rural customers The role of those members (or patrons) is similar to that of stockholders in the investor-owned utility They elect a board of directors from their membership, which oversees the operations of the cooperative However, because a cooperative's members are also its ultimate consumers, they generally take a much more active role than their stockholder counterparts in the operating and administrative matters of the organization

The generation and transmission cooperative (G&T), as shown in the following organizational chart, is also owned by its members, the distribution cooperatives Typically the board of a G&T is made up of two representatives from each member organization Often, one

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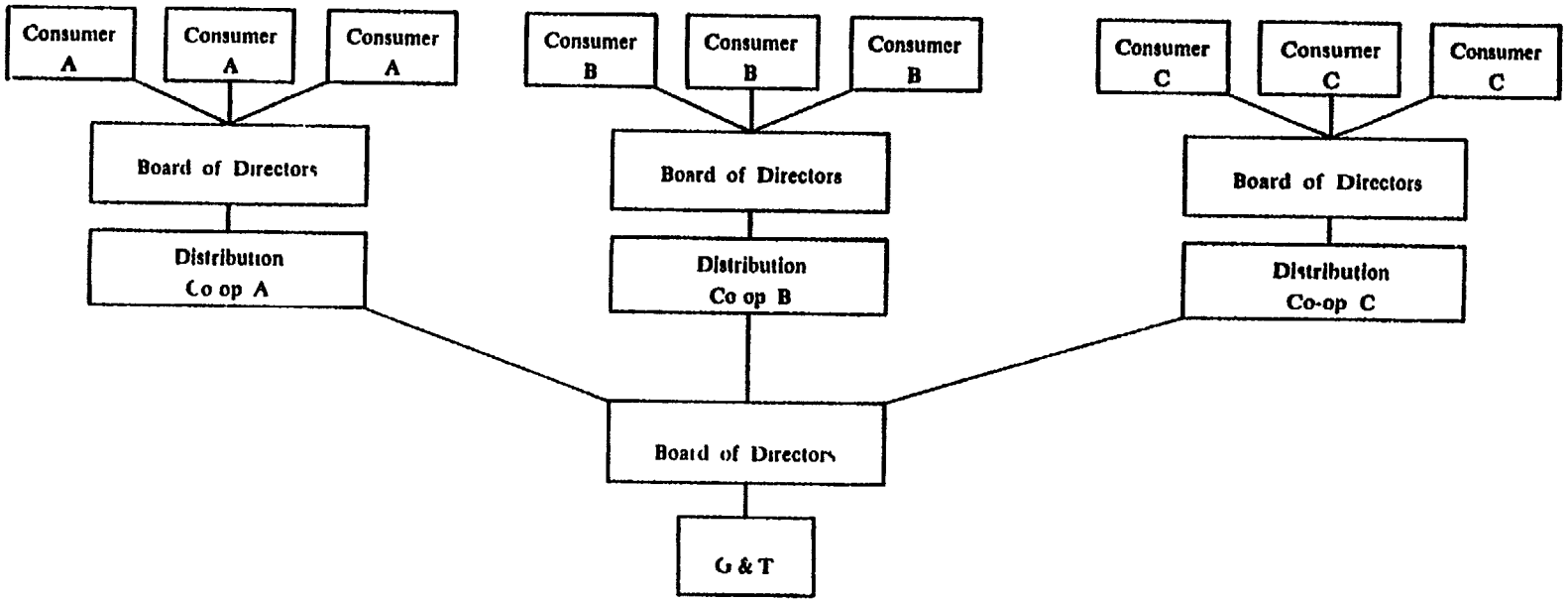
representative is the general manager of the member distribution cooperative, and the other a member of its board of directors

Thus, even though rates may not be subject to outside regulation, the consumer is well represented in the cooperative organization Cooperatives are not, however, immune to consumer-prompted pressures for rate minimization and stability On the contrary, G&T cooperatives, because of the equal representation of individual members on their boards, are perhaps even more aware of the sentiments of their consumers, who not only are board members but also represent several different constituencies

The business relationships between a G&T and its members is somewhat atypical G&Ts usually furnish power to their members under wholesale power contracts, commonly designated as "all requirements"-type agreements These arrangements require that the G&T sell and deliver electricity to its member distribution cooperatives and that the members purchase all their energy from the G&T Because of the joint ownership relationship, the agreement between a G&T and its member distribution cooperatives is not like the typical wholesale power contract Rather, it takes the form of a purchase agreement, under which the member distribution cooperatives pay for power actually received at rates established by the selling G&T These rates are set at levels consistent with RUS requirements to produce revenues sufficient to cover operating and maintenance costs, the costs of purchased power and transmission services, and debt service

Illustration of Typical Cooperative Organization



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[3] Nonprofit Operation

Nonprofitability represents what is probably the most significant distinguishing characteristic between cooperatives and investor-owned utilities Rural electric cooperatives are nonprofit entities organized and operated solely for the benefit of their members The former Rural Electrification Administration (REA), in one of its policy bulletins, succinctly described the relationship that exists between a cooperative and its members and illustrates the capital nature of amounts received from members in excess of the cooperative's operating costs and expenses

> "In the furnishing of electric energy the Cooperative's operations shall be so conducted that all patrons will through their patronage furnish capital for the Cooperative In order to induce patronage and to assure that the Cooperative will operate on a nonprofit basis the Cooperative is obligated to account on a patronage basis to all its patrons for all amounts received and receivable from the furnishing of electric energy in excess of operating costs and expenses properly chargeable against the furnishing of electric energy All such amounts in excess of operating costs and expenses at the moment of receipt by the Cooperative are received with the understanding that they are furnished by the patrons as capital The Cooperative is obligated to pay by credits to a capital account for each patron all such amounts in excess of operating costs and expenses "[9]

The excerpt above clearly evidences the RUS's policy that a cooperative operates as a nonprofit organization and that any margin derived inures entirely to the benefit of the patrons This arrangement establishes a preexisting obligation to return margins to patrons However, given their large capital needs, cooperatives rarely return margins in cash, but rather account for them in a manner that evidences the members' rights G&Ts generally show retained capital as credits to members' capital accounts, whereas distribution cooperatives, because of their large number of members, simply keep records from which an appropriate patronage allocation might be subsequently determined [10] These credits are subsequently redeemed under long-term redemption plans

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[9] Rural Electrification Admin *Capital Credits—Consumer Benefits* Bulletin 102–1 at 9 (1978)

[10] See Rev Rul 72–3 1972-1 CB 105 in which the Service discusses the propriety of patronage dividend deductions if members do not have specific equity accounts

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[4] Taxation

Most cooperatives are exempt from federal income tax under the provisions of IRC Section 501(c)(12) and accordingly avoid the issues and problems affecting taxable companies However, as exempt organizations, they must file annual information returns (Form 990) with the Service Further, exempt cooperatives are subject to the unrelated business tax on exempt organizations If unrelated business income of $1,000 or more is present, they must file Form 990T

The exemption for an electric cooperative is annual and remains in effect as long as the cooperative receives from its members 85 percent or more of its total income [11] "Income" for purposes of this test means taxable receipts (i e , excluding interest on exempt bonds, reimbursements for costs incurred on behalf of another, return of capital on the sale of an asset, and so forth[12]) In 1984, the Service issued proposed regulations defining income for purposes of the 85-percent test to be gross sales minus cost of goods sold The regulations were never finalized and were withdrawn in 1992 [13] Today, approximately one third of the generation and transmission cooperatives (G&Ts) are now subject to federal income taxes, primarily because they have uncommitted generating capacity out of which they make sales to nonmembers [14]

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[11] See Rev Rul 65–99 1965–1 CB 242

[12] Mountain Water Co of La Crescenta v Commr 35 TC 418 (1960) The Mountain Water Co of La Crescenta was a mutual water company exempt from tax under IRC § 501(c)(12) The assets of the company were condemned by the County Water District The condemnation award resulted in a large capital gain The taxpayer maintained that the gain should not be included in the calculation of the 85-percent test The Tax Court disagreed however the return of capital (basis of the assets condemned) was not included in the computation

[13] Notice 92–12 1992–16 IRB 35

[14] Another income item that can affect the 85 percent test is income from the discharge of indebtedness under IRC § 61(a)(12) A discharge of indebtedness is considered to occur whenever a taxpayer s debt is forgiven cancelled or otherwise discharged by a payment of less than the principal amount of the debt The amount of the indebtedness discharged is equal to the face amount of the debt adjusted for any unamortized premium or discount and any amount paid by the debtor to effect the discharge

The Technical Corrections Act of 1988 contains a provision that provides at least a partial solution to this problem Under this provision any discharge-of-indebtedness income resulting from the prepayment of REA guaranteed loans (i e loans made pursuant to § 306 of the Rural Electrification Act) is disregarded in computing the

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Taxable cooperatives face many of the same problems as other taxable corporations They file Form 1120 and are generally subject to the rules of Subchapter C and the procedural requirements of the Code However, unlike other corporations, they are entitled to deduct margins from business done with members to the extent allocated in the form of patronage dividends This is the case even though rural electric cooperatives are not subject to the rules of Subchapter T of the Code, which governs the taxation of cooperatives in general and the patronage dividend deduction in particular [15] However, the deduction for margins attributable to member business does not extend to business conducted with nonmembers or from investments, nor are losses attributable to business conducted with members deductible against earnings derived from nonmember sources [16] The income and deductions of a taxable cooperative otherwise follow, in general, the rules applicable to corporations

One major difference in the taxation of taxable electric cooperatives is in the area of specific "public utility" rules and limitations The Service has held in a number of private rulings that taxable cooperatives that are not subject to "rate of return regulation" are not "public utilities" within the meaning of the tax laws Hence, these cooperatives are entitled to depreciation under the Accelerated Cost Recovery System (ACRS) using five-year lives, energy credits to the extent that they have not otherwise expired, and the use of tax-motivated leveraged leasing

Other differences include procedural rules specifically tailored to electric cooperatives For example, electric cooperatives are not required to send information returns to patrons for patronage dividends [17]

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member income of a rural electric cooperative (i e the discharge-of-indebtedness income would be excluded from both member and nonmember income)

Although the Technical Corrections Act provides some guidance on the treatment of discharge-of-indebtedness income resulting from the prepayment of REA guaranteed loans it leaves open the more general question concerning the proper allocation of discharge-of-indebtedness income resulting from the discharge of other kinds of indebtedness (e g nonguaranteed loans) This problem will either have to be addressed on a case-by-case basis or preferably by specific legislation

[15] See Rev Rul 83–135 1983–2 CB 32

[16] See 26 USCA § 277 which governs the deduction of taxable membership organizations

[17] See 26 CFR § 1 6044–2(b)(2)(iii)

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§ 14.03 Local Publicly Owned Systems

As discussed in §§ 14 01 and 14.02, above, many of the differences that exist between investor-owned and consumer-owned utilities are common to both cooperatives and local publicly owned systems. Both are generally nonprofit organizations exempt from income taxes and operate in a different regulatory environment In addition, local publicly owned systems, like cooperatives, are generally governed by a board of directors made up of consumers

Typically, publicly owned systems include the following four types of organizations

(1) municipal systems,

(2) public utility districts,

(3) state and county systems, and

(4) joint action agencies

This group encompasses almost every state and local quasi-governmental utility, as well as organizations such as joint action agencies, which include member participants from several municipalities Although approximately 75 percent of all the systems are located in communities with populations of 10 000 or less many large metropolitan areas such as Jacksonville, Los Angeles, Memphis, Seattle, and San Antonio, have publicly owned electric systems

Probably equally as diverse as their size and locale is the general environment in which local publicly owned systems operate Many of these organizations are basically self-regulated Some of these organizations, depending on the applicable state law, are subject to the jurisdiction of state public service commissions Others, such as joint action agencies, may have been created by, and are subject to, specific state law, often referred to as "enabling legislation " Unlike cooperatives, however, local publicly owned systems do not fall within the jurisdiction of a specific federal regulatory agency, such as the RUS Instead, certain aspects of their business, such as contract negotiations with investor-owned power suppliers, may be under the control of other regulatory agencies, such as the Federal Energy Regulatory Commission (FERC)

In the absence of required reporting to specific regulatory bodies, the accounting policies and practices for local publicly owned utilities vary considerably Many of the systems have adopted the FERC

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Uniform System of Accounts, while others use variations of this and other systems Some of the joint action agencies, because they float separate issues of municipal bonds to finance specific projects, account for the projects separately in accordance with the requirements of the specific debt instrument

As discussed in § 14 02[1][a], above, FASB Statement No 71 clarified accounting for regulated enterprises such as utilities However, because the issue of accounting for governmental entities was under study at that time, the FASB decided to exclude publicly owned utilities from the statement In essence, the FASB allowed publicly owned utilities to follow Statement No 71, but did not require it Local publicly owned systems usually base tariffs on debt service, but may use depreciation accounting for financial reporting purposes The depreciation rate adequacy issues discussed for cooperatives can also apply to publicly owned systems

In summary, although local publicly owned systems have a number of obvious general characteristics in common with cooperatives, variations exist within the group as to accounting policies and practices and the regulatory environment in which they operate Each system is to some degree different from the next, and its accounting and rate-making practices are more likely to be influenced by state and local regulation than by any of the more common federal regulatory agencies

§ 14.04 Joint Generation

One of the most significant recent developments in the consumer-owned segment of the electric utility industry is joint generation Simply defined, joint generation involves an arrangement under which two or more utilities become business partners to construct, own, and operate electric generating facilities Joint generation projects have become very prevalent in recent years One large project may involve as many as ten or more separate utilities In some cases, the project may involve participation by a combination of investor-owned utilities, cooperatives, and publicly owned systems

Three principal factors probably account for the current popularity of joint generation projects They are

(1) economies of scale,

(2) capital costs, and

(3) sharing of risks

Interestingly, the basic competitive advantages that investor- and consumer-owned utilities have always had over one another—economies of scale in the case of investor-owned utilities, and capital costs in the case of consumer-owned utilities—are the very same reasons prompting them to become partners in joint generation projects Since investor-owned utilities serve more customers, they generally have larger generating facilities, thereby resulting in lower per-unit cost In addition, the increased efficiency of larger units in the conversion of hydrocarbon fuels both reduces the cost of fuel and preserves nonrenewable resources in generating the same unit of energy production However, after years of struggling with regulatory commissions, environmentalists, and escalating interests costs, some investor-owned utilities now believe that joint generation may be the most viable method of constructing new plants By combining resources with consumer-owned utilities, the total financing costs of generating facilities can be reduced Consumer-owned utilities, because of their income tax exemption, have the advantage of issuing tax-exempt debt at rates generally lower than those available to investor-owned utilities

In addition to these benefits, joint generation reduces the financial risks associated with the construction of new facilities In today's environment of ever-increasing construction costs, a utility must build the proper size plant to meet its projected future needs An inaccurate projection of load growth can be a costly error if it results in the construction of a facility that is either too large or too small to service those needs The participation of several utilities in one project spreads these financial risks and reduces the maximum exposure of any one member

Although joint generation offers some rather attractive benefits to its participants, like other business joint ventures, it raises some difficult questions The most common ones are the following

(1) How will construction and operating costs be shared?

(2) How will new members be admitted or existing participants withdrawn?

(3) How will the venture handle the income tax consequences of taxable and nontaxable participants?

(4) How will various legal questions, such as extent of liability and exposure in event of default, be handled?

Nevertheless, joint generation is one of the most significant recent developments affecting the consumer-owned segment of the electric utility industry and one that, based on every indication, will continue to flourish for some time

CHAPTER 15

Business Structures and Management Tools For Competitive Utilities

SYNOPSIS

§ 15 01 Business Environment

§ 15 02 Business Structures
[1] Organizational Model
[2] Business Process Model

§ 15 03 The Planning Process

§ 15.04 Planning Models

§ 15.05 Activity-Based Management—An Overview

§ 15 06 Performance Measurement
[1] Unit Cost Reporting
[2] Productivity Reporting

The business environment in which utilities operate has changed dramatically in recent years It will continue to evolve toward a competitive model in a manner similar to the evolution of the telecommunications industry This chapter summarizes the major changes taking place in the business environment and the structural changes which utilities are making in response to it The chapter also describes planning and management tools that utilities are adopting to support new business structures and to operate more effectively in the changing business environment

§ 15.01 Business Environment

The busin environment in which utilities operate is challenging by any meas Changes in technology and regulation have introduced far more intense competition, with significant pressure on costs and service performance Utilities are responding with changes in structure, strategies, and management practices Some of the concerns and issues facing today's utilities are summarized below

Competition Utilities are losing some of the monopoly power Large cus omers are bypassing local utilities Te logy and regulatory changes are providing alternative ways to se e services utilities traditionally provided Unbundling of services and changes in rate structure have created a need for management information on the cost of service at a level of detail not traditionally required for ratemaking

Regulatory changes The move toward deregulation is in full swing, and with it comes the need for more discreet information on components of a utility's business Management has had to study its cost structure and propose alternative rate structures and, in some instances, alternative orate structures to meet the challenges of a restructured marketplac

Environment Many in the utility industry are convinced that environmental concern will be one of the most pervasive influences on business i e next decade as projects environme costs begin to weigh mo avily Improved cost accounting fo ironmental programs is tial for decisions on projects, pc ation credit transactions recovery, and compliance

Technology Technology's impact can range from the strategic (e g , the impact that high-temperature super nducting materials could have n electric transmission) to the ta (e g , the use of a new trenc ng machine to lay pipe)

Restructuring Many utilities responded to their changing environment by changing their corporate structure Some have established strategic business units such as generation and management services units This structural change may also involve se ng up new legal entit and reporting relationships, or it may inv ve decentralizing or e outsourcing certain business functions or activities Making the nt decisions about restructuring requires the right financial information and may require systems that are more flexible in restating revenue and cost for pro-forma analyses

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INDUSTRY ISSUES AND INITIATIVES

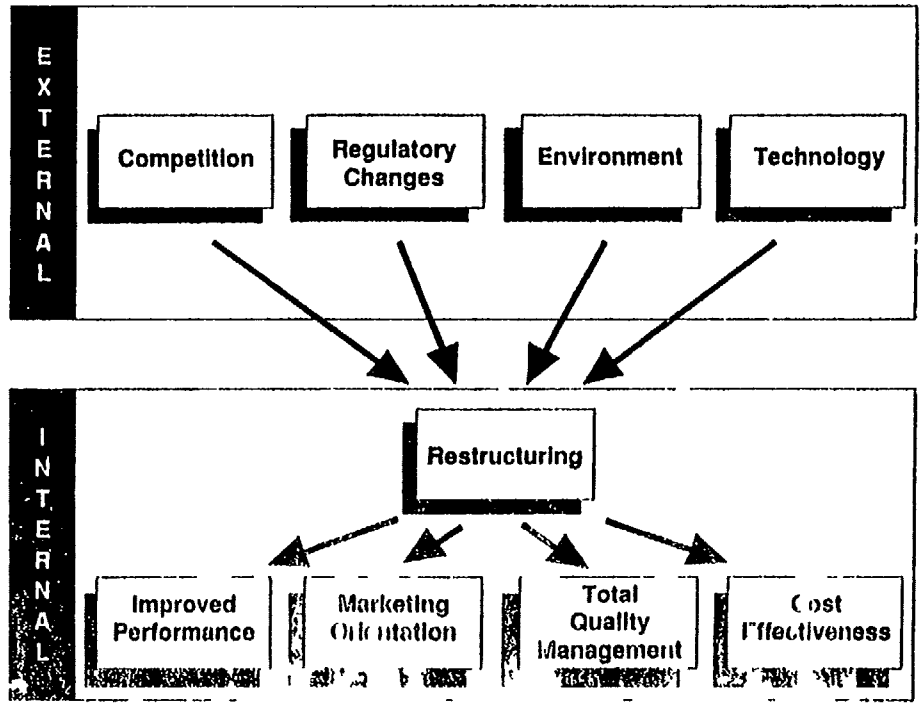

Figure 15-1

(Matthew Bender & Co. Inc.)

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Improved performance The utility industry has been criticized in the past as being a "cost-plus" business Actually, the better utilities have always sought to capitalize on productivity changes and technological innovation to reduce costs and provide better service In addition, the current business environment has forced utilities to become even more oriented toward measuring and rewarding superior performance or excellence Studies of "best practices" and performance-based incentives have helped management demand and receive outstanding performance from people and systems

Marketing orientation The business environment of the past may have led management to focus on engineering considerations or on financial or ratemaking expertise While engineering and finance still play leading roles in utility management, marketing activities have become essential Utilities are developing information systems for marketing programs, customer support, sales force management, and cost management

Total quality management Most utilities have undertaken quality management, continuous improvement, or business process reengineering programs These programs can dramatically improve cost effectiveness and service performance These programs often require new methods of measuring performance and costs such as new methods of planning, management of business processes of several related organizations (crossorganization management), and new information technologies and systems

Cost effectiveness Utilities have renewed their traditional efforts to control expenses because they have recognized that cost is a key component in many competitive strategies, and that regulators will continue to be vigilant in scrutinizing the cost of service The emphasis has changed from mere budgetary cost control to creating value through the products and services provided More emphasis is now placed on measuring units of work activity and tracking the cost of those units as they relate to a total cost of service model

These utility industry trends are likely to be the key issues into the next century

§ 15.02 Business Structures

The restructuring mentioned above affects a utility's organizational definitions and relationships (see § 15 02[1]) and establishes a business process orientation (see § 15 02[2]) § §

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[1] Organizational Model

Utilities have traditionally been organized as monolithic corporations with all operational, financial, and administrative functions performed within the single company structure Multi-jurisdictional utilities usually have separate operating companies for each state, tied to a holding company with a small staff focused on financing The use of a holding company structure increased in the 1980s as utilities acquired or formed nonregulated subsidiaries In these newer structures, the holding company may perform additional corporate functions, such as accounting, purchasing and legal, or there may be a separate business services group that provides other areas of the company with a wide array of corporate functions

The overall organizational structure of electric and gas utilities is changing in response to the competitive market's opportunities and challenges Many utilities are restructuring into business units that may have differing degrees of autonomy In an electric utility the business units often include

- generation,
- transmission (this may instead be a part of the generation business unit or the distribution and customer service business unit),
- distribution and customer service,
- business services, and
- nonregulated businesses

Utilities may also establish business units for fuels acquisition and management, nuclear plant operations or international activities There are many variations in the number and scope of business units and the extent to which they are legal entities Utilities may also outsource business unit functions, examples include information systems, facilities management, materials management, and EDP auditing Figure 15-2 illustrates business unit structures with two examples

These complex organizational models have significant consequences for both accounting practices and information systems Transfer prices for products and services provided by one business unit to others must be determined and applied to measures of products or services provided There will also be allocations of cost which are not based on measured activity The information systems must be able

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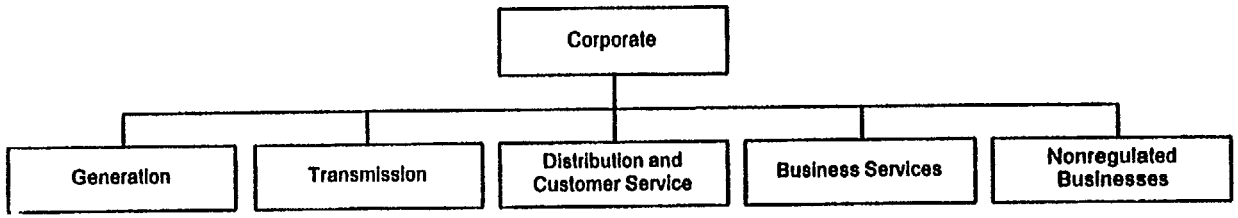
Examples of Business Unit Structures for Electric and Combination Utilities

Integrated Gas and Electric, or Electric Only



Separate Gas and Electric

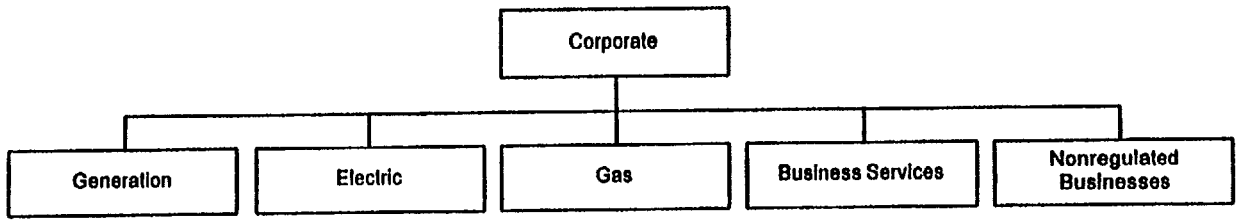


Figure 15-2

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to record and report activity by business unit and to consolidate the business units into corporate entities and by regulatory jurisdiction

[2] Business Process Model

During the 1990s, most utilities have been attempting to improve efficiency and effectiveness by examining their basic business processes and undertaking business process improvement or reengineering An early task in these initiatives is to document a set of business processes which represent what the company does as a whole, without regard to its legal or formal organizational structure These processes often cross organizational lines Figure 15-3 is one example of the business processes that a utility may define

The processes provide a framework for defining the company's activities These activities may then be used in an activity-based management approach to planning and control

Companies may structure managers' and employees' reporting relationships using the business process model rather than the traditional departmental organization Managers may be appointed as "process owners" responsible for conducting their assigned processes using their own resources and those obtained from other process owners according to a set of agreed upon goals

The benefits of a business process approach include the following

- The process view of an enterprise allows executives to see their organization as a "business," with each activity essential to that business
- The business processes may be broken down to whatever level of detail is required for management and analysis of activities
- A business process model is ideal for developing the cost of service by its respective components, for analyzing a value chain, or for a competitive analysis when a competitor is offering a component of the utility's total service (e g , appliance service only)
- A business process model allows management to examine the enterprise from a cross-organizational viewpoint, without actually having a "matrix" organizational structure If the enterprise does have a matrix organizational structure, a business process model helps resolve process managers' accountability issues

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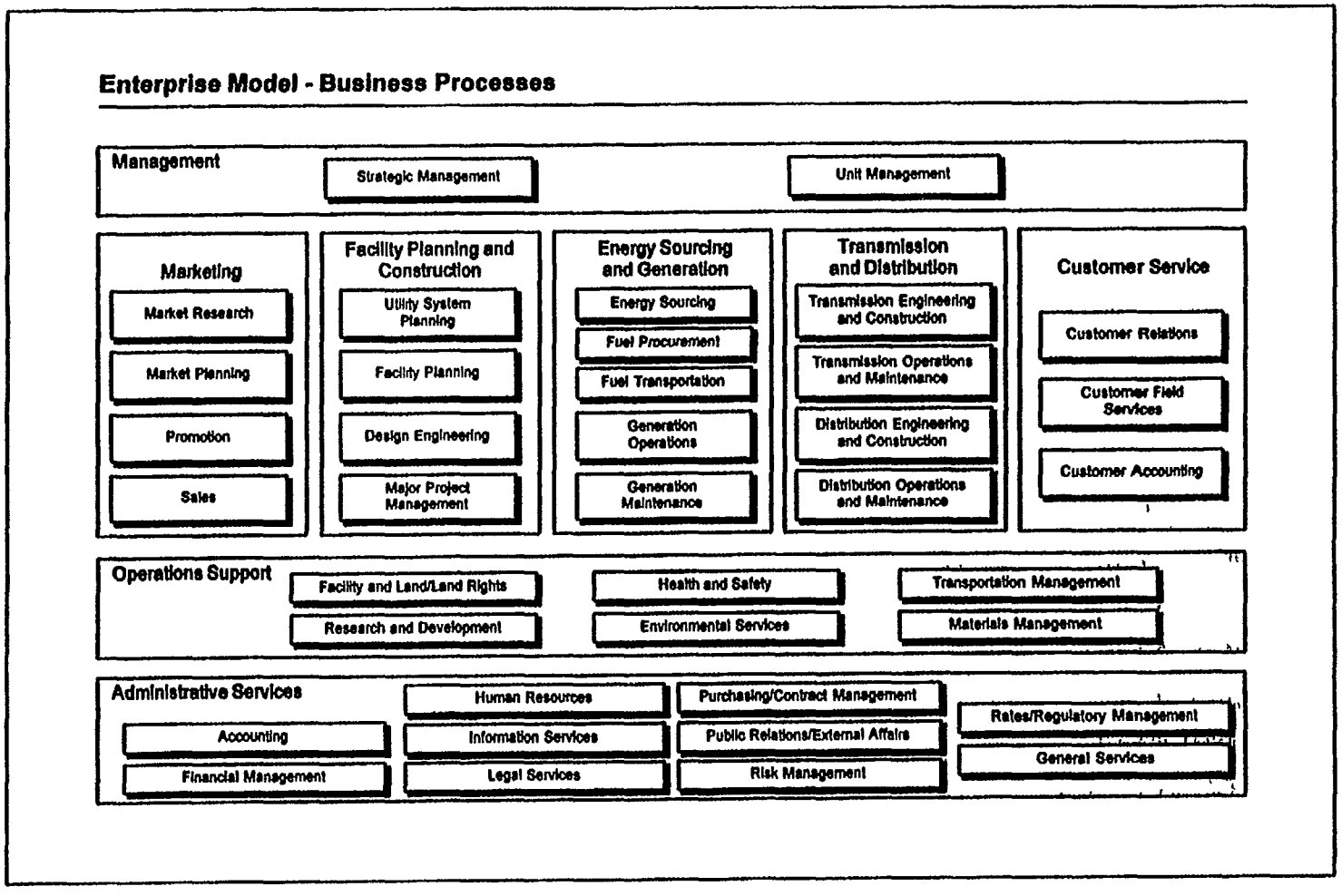

Figure 15-3

(Matthew Bender & Co., Inc.)

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- A business process model can be an integral part of a total quality management or business process reengineering program that focuses on identifying the processes that produce products and services and on ways to improve the quality, cost-effectiveness, and/or responsiveness of those processes
- With a proper information systems design, the business process model, reduced to an activity level, can be used for coding financial transactions so that management can get process and activity costs without compromising the system's ability to meet external reporting requirements If the basic coding is properly structured, a table can be used to look up regulatory codes, and field personnel can use natural activity coding instead of memorizing regulatory accounts and subaccounts

§ 15.03 The Planning Process

Given the more dynamic business environment in which utilities operate and the need to allocate scarce resources to areas of highest value, an effective planning process is essential The planning process at public utilities is similar to that of other large public enterprises but has a different emphasis Like other businesses, public utilities need to

- Establish the mission (What business are we in?)
- Assess the current situation (Where are we now?)
- Set targets (Where do we want to go?)
- Develop strategies (How do we plan to get there?)
- Write action plans (What will we do?)
- Determine milestones and deadlines (When will we do it?)
- Assign responsibilities (Who will do what?)
- Monitor and control (How are we doing?)

The unique characteristics of utility planning are as follows

- The capital intensive nature of the utility industry leads to a heavy emphasis on capital budgeting (which often starts a few months earlier than expense budgeting) and on budgeting maintenance costs (i e , costs for preventive maintenance and repairs)
- Traditional rate-of-return regulation causes some of the planning process to appear to flow backwards, from bottom-line

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profit to expenses to revenue requirements, instead of flowing from revenue forecast to cost of goods sold and fixed costs down to the bottom line

- Annual and long-term production and transmission capacity planning is of major importance Because of the variety of electricity and gas sources now available (because of technological, regulatory, and economic changes) make versus buy decisions have become a part of the capacity planning process Electric utility practices such as demand-side management and conservation marketing also provide alternatives to building new capacity
- While other public enterprises recognize the need to translate their business plans into pro forma financial statements to gauge the impact of their plans on shareholders, utilities also have to consider the regulatory impact, including
  - earning the allowed rate of return,
  - expense rates relative to industry peers,
  - allowable expenses (e g , certain investment expenses),
  - least-cost planning,
  - management prudence, and
  - transfer prices with nonregulated affiliates
- While other public enterprises may use overhead pools to allocate indirect costs, public utilities are required to use clearing pools in specific ways to allocate indirect or shared costs to certain functional accounts

The complete planning process is complex, involves a large number of people, and often extends over a period of six or more months It includes both "top down" and "bottom up" development activities Figure 15-4 illustrates the planning process at a high level

The planning process often includes the following major tasks

Examine business environment and company capabilities The company must evaluate its market position and potential, its energy supply capabilities, and its financial, human, and facilities resources

Review/develop strategic plan The results of the company's business environment and company capability review are used to update or develop the company's strategic plan Given the current industry

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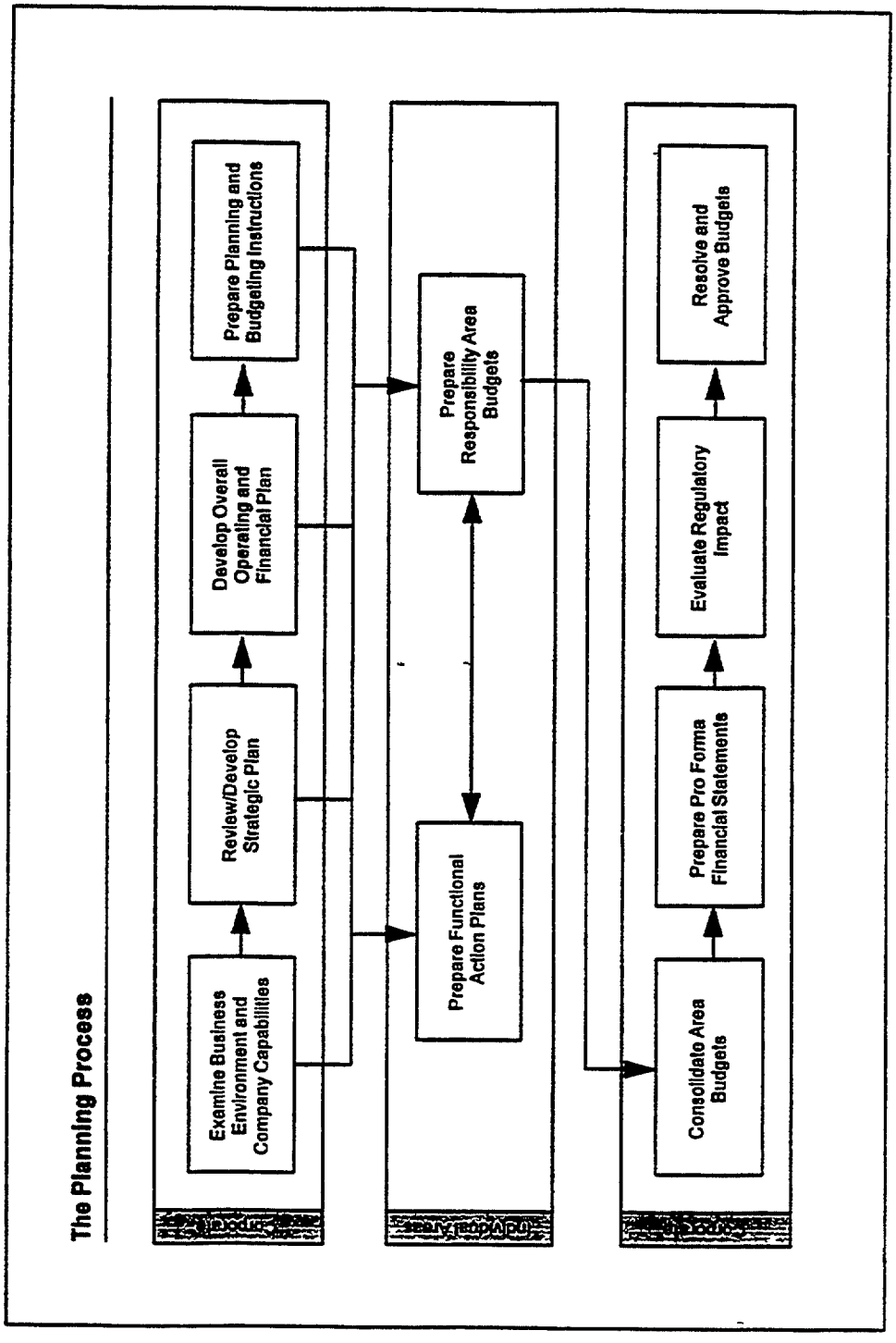

Figure 15-4

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environment, many companies also examine merger or acquisition potential in the strategic planning process

Develop overall operating and financial plan A great deal of analysis and modeling of load, customer growth, and revenue is done at an early point to provide an economic basis for planning In electric utilities, the load forecast and a fuel cost forecast, including purchased power from a variety of sources, are used to develop a capacity plan and a generation operations plan Gas utilities develop similar plans for gas supply and transportation This revenue and energy plan is then combined with other planning assumptions into a set of high level operating and financial plans that serve as a basis for detailed planning and budgeting

Prepare planning and budgeting instructions A planning and budgeting group working with senior management then establishes overall budgeting assumptions and parameters, such as revenue patterns, labor cost increases, inflation rates for other costs, and a set of budget instructions

Prepare functional action plans Managers throughout the organization should prepare plans that describe their actions and goals in support of company strategies and operational needs

Prepare responsibility area budgets Budgets are prepared at lower levels in the management organization (Budgeting practices are described in § 15 05)

Consolidate area budget To prepare for their analysis, budgets are summarized by organizational structure levels and by various other groupings There may be several cycles of review and revision to reconcile managers' budget requests to the economic targets and constraints of the business as a whole An effective process will result in a larger share of resources allocated to the activities that provide the highest value in relation to the company's strategic objectives, and will include a mechanism for relating budgets to strategies A business process view of the company is one such mechanism The traditional budgeting process separates the development of the capital and expense budgets up through the organization until they are assembled into a set of pro forma financial statements Companies which adopt a business process view may combine these activities into an expenditure budgeting process throughout the organization with a restatement for financial purposes at a corporate level

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Prepare pro forma financial statements Budgets are then added to models that contain revenue and energy plans The models support planning for taxes, depreciation, and other financial factors, and generate pro forma financial statements, including cash flow, debt, and investment positions, and various financial ratios

Evaluate regulatory impact The financial plan is then adjusted so it can be stated according to regulatory requirements, and results are determined by regulatory jurisdiction Further analysis for rate case action may be performed separately

Resolve and approve budgets The proposed budgets and related financial plans are submitted for approval by management and the utility board of directors

This planning process is supported by planning models, described in the next section

§ 15.04 Planning Models

Utilities generally examine business scenarios and establish a framework for budget development with a set of planning models Figure 15-5 illustrates a planning model for an electric utility, the process is similar for gas and water utilities

The process begins with load forecasting The utility may use various methods to develop load forecasts At the highest level, the utility may use a regional econometric model to factor into the forecast variables such as

- business conditions,
- labor market conditions,
- housing starts,
- industrial investment in plant and equipment,
- personal income,
- profits,
- interest rates, and
- energy prices

A regional econometric model can be useful for relating the local economy to the national and regional business cycle phase (e g , expansion or recession) The energy demand part of the model can be used to factor in price and income elasticities of demand or price

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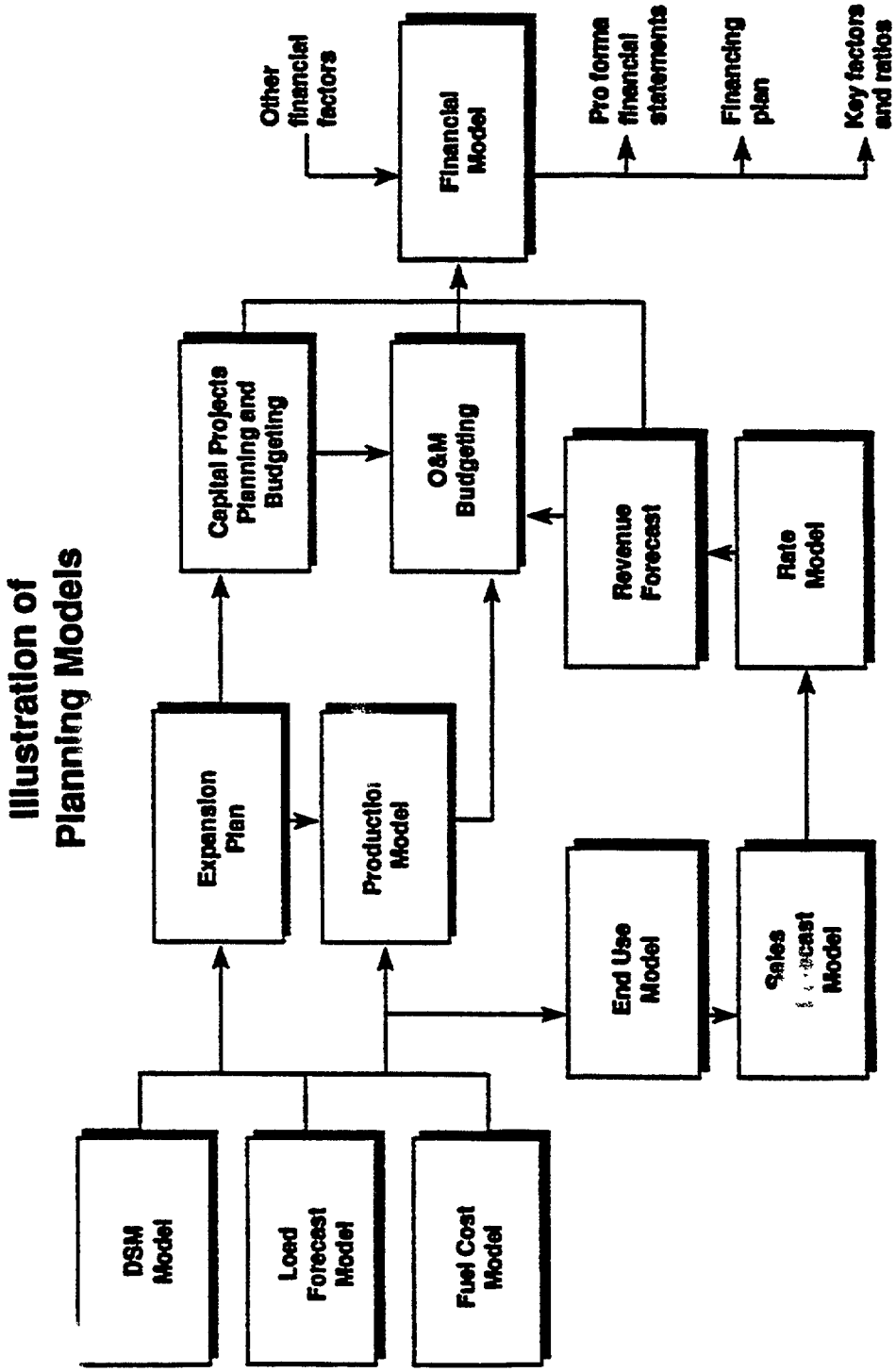

Figure 15-5

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sensitivity may be considered in a separate policy simulation model Time series analysis can be used to project historical load patterns forward If is this approach is used, it is critical that weather normalization be taken into account

A demand side management (DSM) model may also be used to examine and include the impact of demand side management initiatives on load, sales, and revenues

As competitive markets develop further, it is essential to have some way of gathering intelligence about large users who might switch to cogeneration or alternative energy sources Wholesale sales through power pools or other arrangements also need to be estimated and factored with the appropriate rate, usually a marginal rate Another mechanism used to develop a plan is to project the number of customers by class and their energy use by type of load (i e , an end-use model) This approach can help reflect consumer appliance usage trends (e g , consumers' use of heat pumps)

The utility must also consider, in addition to historical and national/regional analysis, the impact of the planned marketing and concentration efforts New programs designed to stimulate or redirect energy demand, if they are effective should have an impact on baseline growth All of these market factors should be included in a sales forecast model

Rates per kilowatt hour (KWH) combine base rates and fuel adjustment factors The base rate is either the current rate for each class of service or a proposed rate Special adjustments may be appropriate (e g , rates collected subject to refund, pending review) A rate model and a revenue model may be used to complete the revenue forecast

A utility uses a production simulation model to determine how to convert energy demand into energy supply Models may project a least-cost solution based on discrete hour-by-hour simulations, including such factors as forced outages and even the necessary ramp-up for flame stabilization These models may be limited in scope to the utility's own service territory, but some include multi-area simulations including predictions of other companies' responses The models take into account projections of fuel prices and provide estimates of fuel costs based on the types of fuels used A fuel cost model may be a separate component of the planning process or may be incorporated

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in the production model An expansion plan ties in planned increases in generation and transmission capacity

The cost budget is the major part of a utility's budget The cost budget is normally divided into a capital budget and an operations and maintenance budget The capital budget normally includes major operating department expenditures for expansion or replacement of network facilities Most of the administrative and general departments budget relatively minor capital expenditures (except for information systems or facilities improvements) Costs associated with capital expenses include direct labor, material, contractor services, engineering design, and allowance for funds used during construction

Large projects normally require specific authorizations, backed up with fairly detailed proposals and work plans The level of detail will depend on how soon the projects will be started The detail must be sufficient to manage project costs

Many projects are grouped into generic blanket authorizations because the details cannot yet be determined, or because they are similar and it makes sense to budget and control them as a group Projects not required for safety or system reliability may have to show a rate of return, on a discounted cash-flow basis, that exceeds some hurdle rate

Operations and maintenance budgets are developed and summarized to be included in the overall financial plan, that is developed with a financial model The end result is a set of pro forma financial statements, along with financing requirements and a set of financial ratios (see § 15 03)

§ 15.05 Activity-Based Management—An Overview

Utilities' traditional budgeting practices are a product of the Federal Energy Regulatory Commission (FERC) accounting structure and of this capital intensive industry's rate base orientation Separate capital and operations and maintenance budgets are developed by FERC account and by cost element (e g , labor, materials, contract services) The operations and maintenance budget preparation process is susceptible to applying a "last year plus x%" method " The results are often ineffective as a management tool Activity-based management can offer a more effective approach to budgeting and cost management

The utility industry is becoming much more flexible in pricing decisions like other cost-sensitive businesses This trend will continue

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as the industry evolves in response to new energy technology, mergers and restructuring, and regulatory changes Cost information to manage and to evaluate pricing options in increasingly open markets is essential Utility managers need relevant, targeted information to

- know what is being spent and why, in the context of the company's strategies and priorities (budgeting should result in resource allocation which best supports those priorities),
- sustain efficiencies gained in business process reengineering or restructuring,
- measure results of spending,
- address market opportunities, and
- make decisions in both a business and a regulatory context

Activity-based management (ABM) is a tool for meeting these needs ABM allows management to plan for, capture, and report costs in a manner that more closely represents the business' actual operations than does traditional regulatory accounting

An "activity" is a defined scope of work that produces a physical or informational result, uses a measurable set of resources, and may have an identifiable "driver" (one or more business factors or events that cause this work to be performed) An activity may represent ongoing, continuous work, or may be a specific project or program An activity may be performed as discrete departmental work or on a cross-functional basis by many organizational units Examples of activities include

- install commercial services,
- maintain the computer-based pipeline monitoring supervisory control and data acquisition (SCADA) system,
- update distribution maps,
- expand a downtown service center; and
- develop an appliance trade-in program

In an ABM approach, budgeting and cost management typically focus on the manager's direct, controllable costs Allocations and overheads are reported at higher levels in the organization, where they are controllable Management reporting of actual versus budgeted cost and of trends in cost typically includes two dimensions (1) cost by activity, and (2) cost by type (e g , labor, materials, contract services)

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for the organizational unit The reporting may include measures of work performed (e g , services installed) or of results achieved (e g , customer calls answered within targeted time), or indicators of goal achievement (e g , compliance with environmental regulations)

An ABM system must satisfy the need for regulatory accounting and reporting The regulatory representation of cost is generally derived by translating activity cost to a FERC or Public Service Commission (PSC) chart of accounts through computer tables This allows field and office areas to use the set of activities that make sense in their contexts and at the same time ensure tight control over the restatement of the costs for regulatory purposes

An ABM approach also views cost as a set of expenditures for resources, rather than as an accounting product operations and maintenance expenses, deferred expenses, and capital project spending are brought together as total expenditures under the responsibility of a particular manager The accounting treatment (expense versus capital) comes into play as the costs are translated for regulatory purposes

Budgeting in an ABM approach is based on company priorities and strategies, and may be based on forecasts of the quantity of work to be done For example, the budget for the activity, "install commercial services," may be based on a forecast of the number of services and on a planned cost for a typical service This calculation may be performed by a budgeting system, and reviewed and adjusted by experienced personnel In the annual budgeting process, or during the year, it may be necessary to reduce or reallocate budgets The ABM approach, with its linkage to both the physical and informational products of the business and priorities, allows decisions to be made based on the business' directions and results rather than "across-the-board "

In an activity-based management approach, activities are identified with business processes For example, Figure 15-3 identifies a summary business process titled "Distribution Engineering and Construction" (See § 15 02[2]) The activity "install commercial services" is a component of that business process Several organizational areas, including marketing, engineering, distribution construction, and customer service perform work on this activity The budgeting and cost management reporting in an activity-based management approach assembles the cost of the work performed by these organizations into

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the cost for that activity This activity cost is then one component of the cost of the distribution engineering and construction business process, along with the costs of dozens of other activities

Activity-based management is particularly well suited to the cost structure of electric and gas utilities, in which the majority of the cost is attributable to field and plant activities The flexibility of activity-based management to match actual operations and projects makes budgeting and reporting more relevant to operational and project managers In many of the organizational areas, the focus on operational costing, which is characteristic of activity-based management, provides a path for linking the activity-based management system to the various detailed planning and control systems, such as transmission and distribution work management (T&D) The T&D example, illustrated in Figure 15-6, demonstrates this linkage and the multilevel structure that can be achieved with an activity-based approach

Here, an activity, install commercial services, has been broken into a number of subactivities relating to job condition types, such as new building installs Many work releases may be processed in the T&D work management system for the new building installs The cost records in the activity-based management system are supported by the operational details in the T&D work management system

To develop a set of activities for use in an activity-based management system, the utility must first identify its business processes and then identify the activities related to the processes This analysis is often an aspect of a business process reengineering project to improve business process costs and service effectiveness Identifying business processes and activities provides a framework for the utility to identify, from various areas of the organization, the resources used in performing each activity Analysis of the processes, work flows, activities, and resource use can provide opportunities for the utility to significantly reduce costs

Activity-based management may also be used to determine the full cost of providing products and services This aspect of costing is becoming increasingly important, as utilities unbundle or differentiate products and services and price them separately Examples of products or services that can be unbundled and priced separately include high reliability power, special billing, and energy management services

Understanding the fixed and variable cost of a product or service is essential to pricing it appropriately The first step in gaining an

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Relationship of Financial and Operational Controls in an ABM Approach

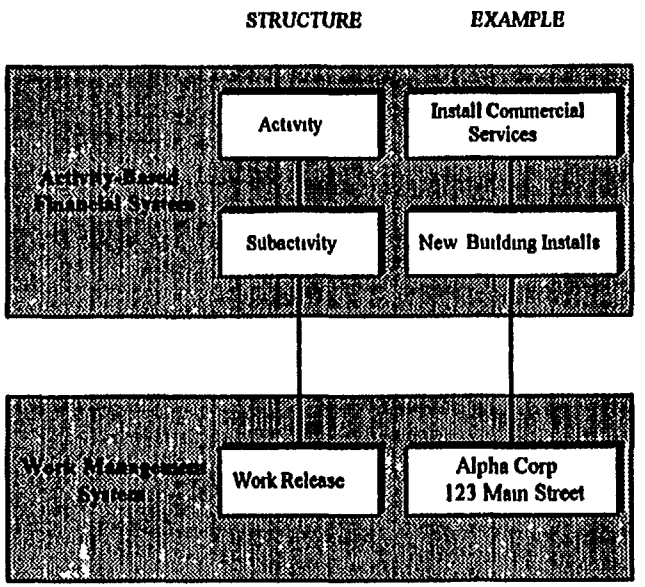

Figure 15 6

Figure 15-6

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understanding of a product or service cost is to use the above mechanisms to identify all of the costs incurred throughout the organization that are attributable to each activity and then to identify which activities are performed to provide the product or service These activity costs, or relevant portions of them, are then assembled into product or service costs

The increased acceptance of activity-based management, coupled with the evolution of organization structures, requires supporting information systems to expand their capabilities Information systems need to be flexible enough to capture and report costs by business process as well as traditional functions (e g , marketing, purchasing, and quality control) and organizational units

A set of integrated systems is used to implement activity-based management a budget preparation system, a financial management system, and a financial reporting system

The financial management system deals with all types of cost data

- operations and maintenance and capital expenditures,
- budget, actual, and committed costs,
- dollars and statistics (e g , resources and results), and
- costs drivers

The financial management system for activity-based management incorporates the capabilities of a work order accounting system and a general ledger system An activity-based management's financial management system contains a number of important relationships, illustrated in Figure 15-7

The source systems (such as payroll, payables, purchasing, and inventory) supply transactions that have activity codes for their cost distribution These transactions are posted to the activity-based financial management records, and activity costs are translated to Federal Energy Regulatory Commission (FERC) accounts for financial reporting

The work/project management systems in the illustration include

- distribution work management system,
- plant maintenance management system,
- major project management system(s), and

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Activity-Based Financial Systems Relationships

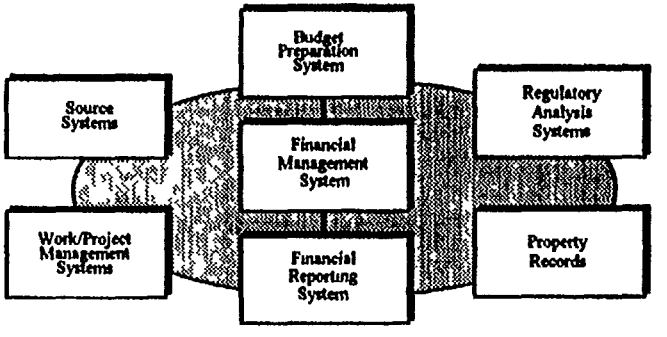

Figure 15 7

Figure 15-7

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- administrative program management system

These systems may generate estimates of resources and costs for work releases and may contain data on actual resource use (e g , person-hours) at the work release/maintenance work order level, as well as work status data. These details support the activity-based management system's dollar and statistical data.

The property records system records the completed cost of work orders in various asset categories (see Chapter 16) A regulatory analysis system uses data extracted from the financial management system and from other systems to determine cost of service

§ 15.06 Performance Measurement

Regulatory agencies and consumer interest groups are demanding that utility management demonstrate its ability to plan and control costs Several tools available in the area of cost control have been discussed in previous sections of this chapter Work measurement tools can be used in conjunction with activity cost management reporting to improve cost control These tools are available to organizations performing repetitive types of work Tools discussed in the following sections are unit cost reporting and productivity measurement reporting

[1] Unit Cost Reporting

Activity cost reporting measures the cost of a particular activity and shows only the direct costs of performing the activity Direct costs are identified by the resources expended (cost elements), unit cost can be analyzed by the labor, material, or other resources that are expended to perform the activity Activities often have physical results that can be measured in units completed

To use unit cost as a cost control tool, the utility must determine the number of units of activity completed in a period of time In this way, the utility can calculate the cost per completed unit (e g , dollars per foot or dollars per invoice processed) and compare it to a predetermined standard It is also valuable to measure trends in unit cost over extended periods of time, particularly if there are not reliable standards available from a work management method or system If more than one organizational unit (division or crew) within the utility performs the same work activity, the utility can evaluate each unit's performance by making a cost per unit comparison

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[2] Productivity Reporting

Productivity reporting measures how effectively company labor performs assigned tasks Productivity measurement differs somewhat from all of the other cost control and reporting features discussed in this chapter, because it does not involve dollar amounts Man-hours or crew-hours are, instead, the typical units of measure More preparatory work is required for a utility to establish a productivity measurement system than to start a cost reporting system The utility must carefully define work tasks and establish standards for the amount of time it should take to complete one unit An effective way to establish good standards is to conduct an engineering time study of each defined task

Once the standards have been established, the utility should compare the actual time taken to perform a task with the standard time to evaluate work performance A useful measure of productivity is the performance rating, calculated below

Performance rating = (standard time/actual time) × 100 percent

If an individual or crew completes its task in less time than the standard, the performance rating is above 100 percent If the actual time required is greater than the standard, the performance ratio is below 100 percent

Another common measure which is important in the determination of work productivity is "utilization" Utilization measures the amount of time an individual or crew is involved in productive work versus nonproductive work and is calculated as follows

Utilization = (productive time/total time reported) × 100 percent

Utilization must be used in conjunction with performance ratings to evaluate productivity A work crew that establishes a performance rating of 120 percent and a utilization rating of 50 percent may not be considered as productive as a crew whose performance rating is 90 percent and utilization rating 90 percent

Performance measurement reports permit managers to monitor the standards they use in their planning and budgeting processes for staff use and productivity To ensure that all activity costs are properly accounted for, these costs are reconciled the total responsibility costs reported by each responsibility center

Figure 15-8 shows a typical productivity measurement report

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Figure 15-8
Productivity Measurement Report
419 Overhead Lines

Current Period Hours						Six Month Moving Average				
No of Units	Actual	Allowed	Actual/ Unit	Perf Ratio	Activity	No of Units	Actual	Allowed	Actual/ Unit	Perf Ratio
100	500	500	0 5	100%	A 1135 Install Underground Residential Service					
10	200	300	2 0	150%	A 1234 Install Distribution Transformers					
10	200	100	2 0	50%	A 4567 Install Vaults					
50	80	80	1 6	100%	A 6580 Inspect Breakers					
	1030	980			Total Hours					
				85%	Labor Utilization					

Figure 15-8

This report does not show dollar amounts It compares actual man-hours to standard man-hours by multiplying the "number of units completed" (left column) by the unit standard (which is not shown) The "perform ce ratio" (fifth column) is the allowed hours divided by actual hours multiplied by 100 percent If a manager surpasses the standard, the manager's performance ratio is above 100 percent "Labor utilization," at the bottom of the report, denotes the percentage of time this center performed productive activities, as opposed to being nonproductive The data is shown for a current period and for an extended period of time (e g , six months' moving average in this example)

To use this data to improve crew performance and remove bottlenecks to productivity, crews should receive productivity reports on a short cycle (e.g , bi-weekly) This information will help management determine the reasons for variances and develop solutions to problems

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CHAPTER 16

Utility Management Information Systems

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§ 16 03 Overview of Application Systems

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§ 16.20 Data Processing Considerations
[1] Coding
[2] Timing of the System
[3] Front End Validation
[4] Ease of Modification
[5] Personal Computers

§ 16.01 Introduction

Chapter 15 described the organizational and business process framework within which utility company activities are planned and managed, and introduced activity-based management as a mechanism for analyzing and managing performance It also provided an overview of utilities' planning processes and illustrated management reports that measure results against those plans This chapter provides an introduction to the information systems public utilities use to support planning and management of major business activities This chapter discusses information systems that directly support financial functions and those that indirectly affect financial records and reporting There are many other information systems in a public utility which support operations and technical activities that are not covered in this material

The term 'application systems" is often used in referring to systems that support business activity (e g , a general ledger system or an automated mapping system) and is used throughout this chapter This chapter addresses applications systems only and not other software that these systems may use to perform technical functions (such as data base management, inquiry and reporting, and security administration)

§ 16 02 Information Technology Environment

Information technology in the 1990s offers many hardware and software options, from centralized mainframe computers to the ubiquitous desktop or laptop personal computer (PC), as well as models for use of information technology

The most popular model for use of information technology is the "client/server" model In this model, a number of "client" computers, primarily PCs and workstations, connect to "servers" through a data communications network The servers are often midrange computers or large workstations and may be assigned to specific duties in the network, such as network management, data base management, or printing A mainframe computer may also act as a server in this technology model The network is essential to the client/server model and often comprises a large proportion of the technology investment

Practically all large utilities use the client/server model in a "three tier" structure which includes centralized mainframe computers with very large amounts of disk storage, midrange computers or servers, and PCs or workstations Figure 16-1 illustrates this structure

The information systems described in this chapter have, in years past, been mainframe-based systems Many utilities continue to use mainframe-based systems As utilities replace their mainframe-based systems, they are likely to consider software packages that use client/server technology Utilities are also likely to use client server technology to develop systems that are unique to a company's operations or for which they can find no acceptable software package Client/server technology, and the software packages that use it, provide greatly improved access to data for inquiry, analysis, and reporting

§ 16.03 Overview of Application Systems

The schematic in Figure 16-2 provides an overview of the major application systems electric and gas companies use to support their business activities As mentioned above, a utility often uses many other application systems to serve specific purposes and/or users that are not included in the scope of this chapter or this schematic These 25 systems are organized into several logical groupings

- customer/market management,
- work management,
- planning models,
- fuel or gas supply management,
- resource management,
- facilities management,

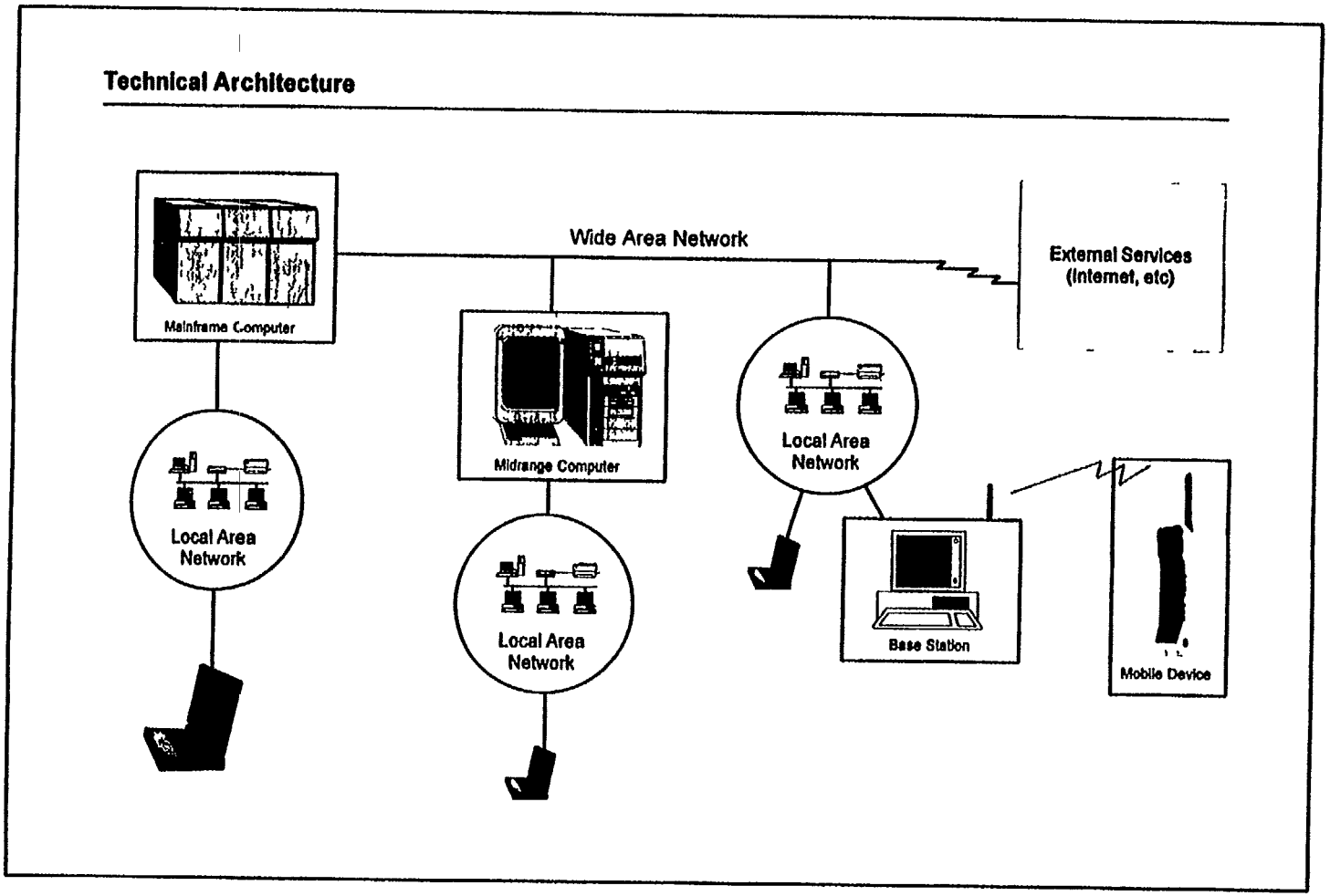

Figure 16-1

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- financial management, and
- human resources management

Some of these application systems may be implemented differently, even with different software, in various parts of an organization For example, a nuclear utility may implement a materials management system for its nuclear plant operations and a separate materials management system for use in other functional areas of the company The advent of business unit structures described in Chapter 15 is likely to increase the number of multiple implementations

The remainder of this chapter provides a brief description of each application system identified in Figure 16-2 and identifies key considerations in integrating and effectively using these applications

§ 16.04 General Ledger and Management Reporting Systems

For utilities, as for other large enterprises, an integrated financial system typically performs the following major functions

- general ledger accounting,
- consolidation and elimination,
- financial statement reporting,
- cost allocation,
- top management reporting,
- budget preparation and reporting, and
- responsibility reporting

Depending on the utility, this system may be called the "general ledger," "financial management system," "financial information system," or other similar names Other functions that might also be a part of the system (or part of a closely related system) are

- work order accounting,
- internal billing,
- decision support, and
- executive information

Although all of these functions may be integrated into a single system, it is useful to examine each major function in some detail

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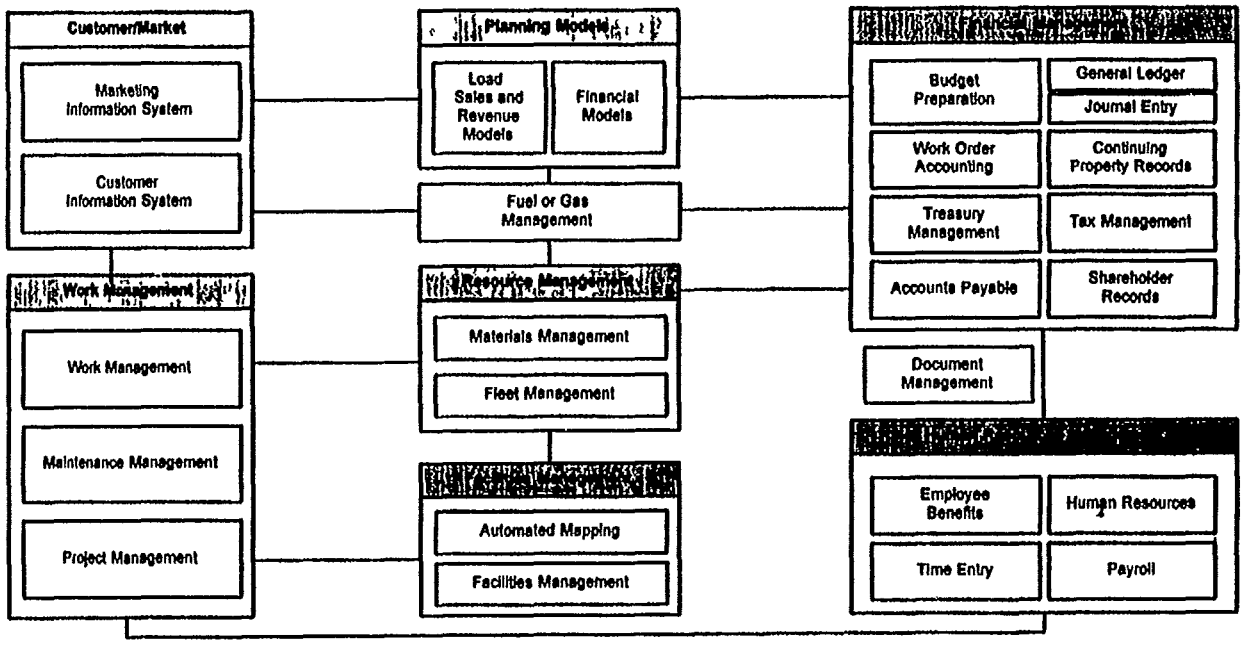
Overview of Application Systems



Note This schematic includes major systems found in a utility they are organized into groupings having common databases and users There are many interrelationships among them A utility will have many other information systems for specialized purposes which are not depicted here

Figure 16-2

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[1] General Ledger Accounting

The general ledger is the core of the financial systems It is used to record financial data, at summary and detailed levels, for the entities that comprise the corporate structure The general ledger may contain subledgers that contain details of transactions and summary data for specialized purposes, such as individual debt issues, or revenue and billable expenses for an area which charges other responsibility areas for its services The general ledger system usually produces a wide variety of reports, which may be classified into these groups

- company-wide financial statements for external purposes,
- jurisdictional financial statements for external and internal use,
- financial statements for internal purposes,
- financial analyses (for specified groups of accounts, locations, or other aspects of the business),
- responsibility reports or budget performance reports,
- budget variance summaries and exception reports,
- trend reports of costs in various categories,
- documentary reports such as ledgers, transaction journals, and cost allocation journals, and
- audit and control reports

Many companies provide for downloading of general ledger data to departmental servers or PCs, with appropriate security, for analysis and reporting

The general ledger receives data from many subsystems and posts it at a level of detail specified in the general ledger system's design The incoming data may be statistical as well as financial For example kilowatt hour (KWH) sales or payroll hours may be used The general ledger also has the capability to make journal entries directly This feature is especially suitable for certain accruals that are needed only for external reporting purposes

The general ledger system is expected to maintain balances, provide the key to an audit trail for all transactions that affect the general ledger, and maintain the controls necessary to ensure the integrity of the accounts In addition, this system generally performs an important role in the validation of all data, because the rules and tables concerning valid accounts and responsibility centers are normally

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maintained as part of the general ledger Thus, while the accounts payable system may validate a vendor number against a vendor master file in the accounts payable or purchasing systems, the account distribution for an expense voucher typically is validated against a file in the general ledger system Furthermore, because some aspects of the distribution may have been deactivated after the expense voucher was originally entered, the general ledger provides an additional validation test as the accounts payable entries are interfaced with the general ledger

The general ledger operates in several modes, depending on what procedure is needed

- table maintenance,
- normal entry posting,
- statistical or memo entry posting,
- account allocation,
- month-end closing,
- year-end closing, and
- reporting

An important consideration in the effectiveness of the general ledger is the timeliness of the reporting The manner of posting normal entries and implementing month-end closing cycles affect the general ledger's timeliness Some utilities and many companies in other industries are changing the monthly closing process to provide quarterly, in connection with the preparation of quarterly financial filings, a full set of allocations and accruals that are relevant for external financial reporting This approach, usually accelerates the regular monthly closing but does not affect information on budget performance and other indicators of financial performance

[2] Consolidation and Elimination

As described in Chapter 15, utilities are adopting various structures which may include nonregulated entities Like other industries, utilities must consolidate these entities for corporate reporting Intercompany or intracompany transactions, among the regulated and nonregulated entities and among organizational units within the regulated entities, may require elimination for consolidated reporting

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General ledger systems using modern software packages have a company code in each record, that may be used for legal entities, jurisdictions, or other components of the company structure, such as business units or subsidiaries Utilities may use this company code sy n to maintain recordkeeping for all consolidated entities in one sy m Alternatively, a utility may use separate general ledg systems for the nonregulated entities, to strengthen their independence

To the extent that transfer pricing or internal billing is employed, it may be necessary for the financial system to identify intercompany transactions and eliminate them in consolidation Sometimes elimination is done through a clear account For example, every department may receive a usage charge or each vehicle assigned to it The charge may be based on the budgeted amount of cost to maintain and own each vehicle The actual cost for the vehicle(s) is then charged to a specific clearing account, which also receives a credit from every department for all of the departmental charge-outs Any difference between the actual and budgeted costs may be shown as the residual cost to the transportation responsibility center; or the residual may be charged back to the departments on a pro rata basis

[3] Financial Statement Reporting

The general ledger system must produce many different reports, including the financial statements—the income statement, balance sheet, funds flow, and other schedules required for external reporting The format of the financial statements may differ for various external users The regulatory agencies require certain schedules The format for these schedules often is not the same as the one that utility management wants to communicate to its shareholders, bondholders, or bankers Therefore, a flexible system that will take the data from the financial database and produce accurate reports in each of the required formats is needed Some utilities download financial data to PC-based application to generate regulatory reports

Part of the flexibility that may be required is the ability to present prior year data in some type of restated form

[4] Cost Allocation

Public utilitie e cost allocation in general accounting more extensively thar ost other industries Unlike most industries that use cost alloca load direct labor with overhead (e g , benefits

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and taxes), utilities are required by regulatory agencies to segregate benefits associated with operation and maintenance work into separate expense accounts However, for capital projects, utilities are allowed to include benefits in a capital overhead rate

Utilities also have been especially sensitive to the allocation of overhead to capital as opposed to expense, because capital becomes part of the rate base, while expense is reflected only in the current year Typically, utilities allocate the following costs to capital projects for accounting and regulatory purposes

- engineering design costs for capital projects,
- allowance for funds during construction,
- tools and equipment maintenance costs and depreciation,
- vehicle maintenance costs and depreciation,
- material handling costs,
- supervisory labor; and
- benefits attributable to direct and supervisory labor costs

In addition, utilities may be required to separate regulated and unregulated business costs, and the costs of the different regulated business lines, such as electric and gas service or long distance and local telephone service

These complex requirements call for a very powerful and flexible cost allocation system that provides an audit trail As was described in Chapter 15, cost allocations may be excluded from cost management reports which focus attention on direct or controllable costs

[5] Internal Financial Reporting

The senior management of an enterprise generally requires considerably more information than is needed in financial statements for external reporting For example, external reports usually include a comparative income statement, but comparisons to budget are rarely provided in an annual or quarterly report to shareholders

Because so much of management's attention often is focused on responsibility reporting and budgetary control, with their emphasis on control over capital expenditures and operations and maintenance expense, it may be necessary for the general ledger to provide a "crosswalk" between the budget reports and the external financial

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reports It is not uncommon to have a projection that shows departments on budget and, yet, have the utility miss its earnings goal This situation could be the result of the mix of capital and O&M expenses in departmental budgets, allocation of joint costs to capital and O&M expenses, weather normalization, or many other factors

A good reporting system for top management should address the "crosswalk issue" by providing sufficient analysis to link external and internal reporting

[6] Responsibility Reporting

An important component of a utility's management reporting mechanisms is responsibility reporting Responsibility reporting is structured along organizational lines, with responsibility areas identified throughout the organization The manager of each responsibility area has a budget and is accountable for managing activities to achieve the budget's expectations Periodic responsibility reports compare actual results to the budget for each area and identify variances Most entities have a procedure for analyzing and explaining significant variances The results for each responsibility area are summarized and "rolled up" to the next higher organizational level, usually as a one line summary At the next higher level, the report includes costs that are the responsibility of that area's manager Figure 16-3 illustrates a typical responsibility report and one level of roll up that incorporates the concepts described below

In responsibility reporting, each manager of an area is responsible only for the costs that the manager can actually control The area manager's performance against budget should not be affected by costs incurred elsewhere in the organization, such as corporate overhead, depreciation, and interest These costs are controlled by other areas of management

Management reporting has traditionally incorporated utility accounting principles for categorizing costs as capital or expense for financial and regulatory purposes Utility responsibility reports have generally included only costs that will be treated as operations and maintenance expense for accounting purposes, capitalized costs are presented in a separate set of work order or project cost reports This approach can generate misunderstanding about the cost performance of responsibility areas, and can lead to inaccurate recording of costs in to meet budget targets in one category or the other Utilities that are upgrading

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their budgeting and cost management practices may adopt an expenditure management approach in which the accounting distinction between capital and expense is not reflected in the responsibility reports, but is still used in the financial records and statements Expenditures by line item charged to a responsibility area are compared to a budget that was similarly prepared on a total cost basis Figure 16-3 is structured with this expenditure approach, as indicated by the "capital projects" line in the applied cost view Project cost reports will provide details of this line item

[a] Applied/Incurred Views

Responsibility reporting typically provides two views of costs being managed in the responsibility area

(1) *The applied view* addresses the purposes toward which costs are expended and applied

(2) *The incurred view* identifies the types of costs incurred

For example, a marketing representative may spend his week making calls on customers His expenses include his salary (regular and overtime if applicable), travel, lodging, and meals That is the incurred view—by type of expense or resource used The applied view asks why he spent his time and money Was he providing customer service or marketing new services? Was he calling on commercial or multifamily residential customers? The account coding approach used by practically all utilities supports this reporting mechanism Figure 16-3 illustrates incurred and applied views

The responsibility reporting system may report both views Total cost may be the sum of resources expended by category, such as labor, material, purchased services, or other charges Total cost, however, also will be the sum of charges applied to operations accounts, maintenance accounts, deferred accounts, and capital accounts In both cases, the detail should be sufficient for budgetary control When using activity based management, total cost will also be the sum of the activity costs, which are translated to the regulatory accounts

[b] Variance Analysis

Explaining significant variances is an important aspect of responsibility reporting In an activity-based management system, budget variances can be analyzed much more meaningfully Assume that the

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Responsibility Reporting

Responsibility Summary — Incurred Cost — Vice President — Page 1

	Actual	Budget	Variance
Area 123	1000	1200	(200)
Area 456			
Area 789			
Total	5000	6000	(1000)

Responsibility Summary — Applied Cost — Vice President — Page 2

	Actual	Budget	Variance
Expense			
Capital			
Deferred			
Total	5000	6000	(1000)

Responsibility Report — Incurred Cost — Area 123 — Page 1

	Actual	Budget	Variance
Labor			
Contractors			
Advertising			
Auto Expense			
Total	1000	1200	(200)

Responsibility Report — Applied Cost — Area 123 — Page 2

	Actual	Budget	Variance
Residential Marketing			
Customer Support			
Capital Projects			
Total	1000	1200	(200)

Figure 16-3

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budget for a particular activity was developed as a budgeted number of units of work activity multiplied by a budgeted cost per unit The dollar variance can be traced to two causative factors (1) activity (unit) variance, and (2) activity (unit) cost variance The first variance tells the manager if the volume of work or service level is above or below budget, and the second variance tells the manager if the spending per unit is above or below budget Without this analysis, a manager who saw that his spending for a particular maintenance category was right on budget might never realize that the scope of work on maintenance performed actually was far below what was budgeted He might have that information in a maintenance system, but he would have to make the connection for his variance analysis and reporting

If the activity-based system emphasizes labor productivity, the activity cost component may, itself, be decomposed into a productivity component and a labor cost component If a unit of a work activity is budgeted to require 20 man-hours to complete, and labor is budgeted to cost $15 per hour (direct labor only), the budgeted unit cost would be $300 per unit of that work activity A variance of $50 per unit could be traced to either a productivity variance or a labor cost variance.

If a group of employees can work on specific tasks that have well-defined productivity indexes, it may be possible to measure their productive and nonproductive time and to track their utilization rate as follows

utilization = productive hours/total hours

The utilization rate is an essential factor in determining the total labor cost that should be applied to productive work in order to determine the cost of an activity

[c] Effectiveness Indicators

Today, with an increased awareness of the need for continuous improvement in total quality, some utilities are including performance indicators in their management reporting systems to track the effectiveness of their activities in addition to their efficiency Examples of effectiveness indicators include

- response time to customer calls,
- customer satisfaction,
- reworks or callbacks due to poor quality,

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- outages or leaks,
- equipment downtime, and
- parts out of stock

In addition, there are efficiency indicators which differ from budgeted cost, labor productivity, or labor utilization Examples of these indicators are the following

- inventory turnover;
- equipment utilization,
- facilities utilization,
- heat rate,
- fuel efficiency,
- return on short-term investment

As these and other indicators are used more widely in management goal setting and performance measurement, budgeting practice will have to expand to include them

§ 16.05 Budget Preparation System

Chapter 15 describes a utility's planning process, including the preparation of budgets That process often requires extensive time and effort Effective automated support for budget preparation is essential to managing the planning process and to making it more acceptable to the many people in the organization who are involved

A budget preparation system usually contains several components

- A mechanism to support collection and development of data specific to a functional area or business process and that underlies the financial data in the budget for that area or process The data may relate to physical work to be performed, such as new service installations, maintenance operations, and marketing programs The data may be turned into financial budgets through costing out (allocating) the physical units of work with expected unit costs In whatever form it takes, this component is structured in a manner which relates to the activities of the functional area and is most often designed and maintained by that area
- A position control system can be included in the budget preparation process to collect information on each

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organizational area's planned staffing levels, to manage the organizational structure within parameters such as span of control, and to derive information on organizational development needs This system may also establish costs for each responsibility area's staffing plan using the established salary and wage structure, including expected changes in compensation levels, to provide the labor component of the budget

- The corporate budget group develops standard budget templates and provides them to the organization as the mechanism for submitting budget data in a standard format The templates are usually a set of PC-based spreadsheets They should be easy to use and familiar to the people throughout the organization who will prepare budget data The templates will contain data to support the budgeting process, such as last year's budget and actual data, and this year's budget and actual data to date
- A mechanism to upload the budget templates to a centralized budgeting system, which may be the general ledger system itself
- Budget analysis programs that compile the budget data submitted by the individual responsibility areas, perform validations and comparisons, and consolidate the data into financial and regulatory categories These analysis programs may also cross-check intracompany charges and perform allocations

The budget will often be revised several times during the preparation process After final approval, it can be input into a data processing system that will automatically report on performance versus budget when the system receives performance figures

§ 16.06 Executive Information Systems

Because of a utility's magnitude and complexity a great deal of information is available about customers, operations, financial performance, personnel, markets and competition, regulatory and legislative actions, environmental programs, and dozens of other matters Utility executives need summarized information that supports decision-making and monitoring of key processes and developments

Many utilities have implemented an executive information system (EIS) to meet this need for focused and timely information at the executive level An EIS presents information, extracted from internal

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and external sources, on a terminal or PC in graphic and data formats The information is easily available in logical groupings through a set of menus or icons, and often includes.

- key financial performance data, possibly displayed as trends, ratios, variance from target, and so forth,
- external financial data, such as stock prices and financial data of peer utilities,
- budget performance and key indicators of efficiency and effectiveness,
- customer and revenue statistics and trends,
- customer satisfaction and actions,
- market and competitor data,
- generating plant operational status and statistics,
- system outage status and restoration history,
- human resources data, including positions open, head counts, overtime, union matters,
- environmental program results and violations

These types of information have varying degrees of volatility, the date and time aspects of the information must be indicated The information provided to any single executive may be tailored to his specific interests

Some EIS implementations allow for "drill down" into one or more levels of supporting detail This detail may be in the EIS data base or in the data bases of other business or operational control systems Many software products are available for implementation of an EIS

§ 16.07 Project Cost Management

A utility conducts many types of projects each year, ranging from routine maintenance and distribution to plant refittings and transmission facilities construction Cost control for these various projects is essential and must be considered in the context of the company's overall financial and budget management practices and systems This section provides an overview of the cost planning and control mechanisms appropriate for various groups of projects

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[1] Project Control

Project control has three dimensions

(1) achievement of a project's technical objectives and specifications with acceptable quality,

(2) completion of the project on schedule, and,

(3) completion of the project within budget

Important relationships among these dimensions and tools help achieve the dimensions individually and collectively Cost control is one such tool

Cost control for projects depends on the effective use of the following components

- budgets and/or estimates that provide a useful and realistic basis against which to monitor and control actual costs,
- a data collection process that captures and makes available resource and/or cost data on a timely basis and at an appropriate level of detail,
- a cost reporting system that compares actual cost to budget or estimated cost at appropriate levels of detail and with exceptions and trends identified Included and excluded items should also be clearly specified in the definition of "cost" Committed cost, i e , the cost of goods and services for which contracts and purchase orders have been released and receipt has not taken place, is often included, as may estimates of the cost to complete These additional cost components provide a "look-ahead" to the likely total cost of a project or project component

For large scale projects performed over many months or years, project cost control may also include expenditure forecasting and tracking to provide data to the financial planning and treasury management personnel regarding the timing of major expenditures Project budgets or estimates may also need to include escalation factors to reflect planned labor or equipment price increases and the impact of inflation on other costs

[2] Project Reporting System

The principal objective of project reporting is to provide project management with a tool to help control the cost of both construction

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and O&M projects Another objective is to maintain the information necessary to facilitate the property accounting functions of maintaining the work in progress ledger, closing and unitizing work orders, and transferring work in progress to plant accounts

A project can be defined as an undertaking with one or more tasks, a recognizable beginning and end, and a defined objective to be achieved for which cost reporting is desired Projects can be identified at various levels as follows

(1) *Budget item*—This is the highest level of the project This type of project is usually identified to top management in the annual construction budget as a budget line item

(2) *Work order*—This level is usually used by a utility to define a specific scope of work and to authorize the expenditure of funds under a specific budget item Utilities often use multiple work orders to subdivide larger projects into smaller portions for reporting control and assigning the proper account distribution Utilities use blanket work orders to define a financial authorization and a cost collection mechanism The utility then releases numerous job orders (many other names are commonly used) to perform work within the scope and spending limits defined by the blanket work order.

(3) *Work breakdown structure*—A comprehensive project reporting system permits the breakdown of projects into work packages in hierarchical structures referred to as work breakdown structures (WBS) which are used to

(a) plan work scope,

(b) estimate costs,

(c) control expenditures of resources and costs, and

(d) report progress, costs, and variances

Work breakdown structures are used for major projects extending over many months instead of (or in conjunction with) multiple work orders

(4) *Master project*—Master projects are used to combine the costs of two or more work orders not included in the same budget item

A comprehensive project module allows automated budgeting of "units of progress" for routine project(s) using a standard cost of the

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units Expenditures are recorded in terms of completed units as well as actual costs incurred A progress variance can then be measured in terms of dollars by comparing budgeted units of progress at standard cost to actual units of progress at standard cost Cost variance is measured by comparing actual units of progress at standard cost to actual costs incurred

In addition, the project reporting system should process and report charges measured in dollars, man-hours, and units of progress The charges can be capitalized, expensed, or deferred for accounting purposes In other words, there is no need for a system requirement to separate capital projects from expense projects A project should accept any type of accounting charge if appropriate

Figure 16–4 provides an overview of a project management system Major components include

- A project initiation module used by people authorized to initiate a project to enter basic data about the project, including its budget and authorization status
- A planning and estimating module which supports development and documentation of project plans and resource estimates This module utilizes various cost estimating factors and values stored in system tables and may utilize retirement unit definitions and codes in tables maintained by the continuing property records system
- A resource scheduling module which generates and maintains a master schedule for groups of projects and individual projects as well as segments of projects This module may also maintain records of resources (e g , crews, technicians, contractors, equipment) and their availability and commitments
- A project control and reporting module which maintains project master data bases and generates management reports The project master data base usually contains information on the physical resources used (e g , man hours) and on the estimates, projections, schedules, and status indicators Actual cost information may be in the work order accounting system, which receives charges and credits from the various financial and resource systems (e g , payables, payroll, transportation)
- A project closing module which facilitates the closeout from technical and accounting perspectives The accounting

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closeout, which includes unitization, generates transactions for posting to the continuing property records system and journal entries for the general ledger

Additionally, various configurations of project management systems support the different types of projects (large versus other) and the various relationships with other systems

[3] Large Projects

Not all projects have the same reporting requirements In general, a utility project reporting system recognizes two distinct classes of projects with separate cost control requirements—large projects, such as construction of a generating station or a natural gas storage plant and other projects which are smaller in scope and require less detailed reporting

Large projects may be multiyear and require the expenditure of many millions (even billions) of dollars Because of their size and their impact on the utility, large projects require a major, detailed reporting and control effort In addition, projects are subject to greater external examination and regulatory scrutiny Comparison of actual costs to those which were planned in the annual construction budget is not adequate to attain good control To be effective, a project cost planning and control system provides for the subdivision of a large project into subprojects and subprojects into work package Work packages define the work breakdown that is used by engineers to estimate costs and plan construction This work package breakdown is sometimes called the work breakdown structure The project cost system should permit the comparison of actual expenditures to estimates at the work breakdown structure (WBS) level of detail In addition, the project cost system should facilitate refinement of estimates during the course of a project At the WBS level of detail, original estimates, actual expenditures to date, commitments, and current estimates to completion should be available Figure 16–5 illustrates a work breakdown structure

Frequently, it is not prudent to wait until an actual expenditure has occurred to obtain access to cost information because of the size of individual purchases and the lead time involved To give project management as much advance cost information as possible, commitments (representing the unexpended or incomplete portions of purchase orders) are charged to projects The project system reports a

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Conceptual Design of a Project Management System

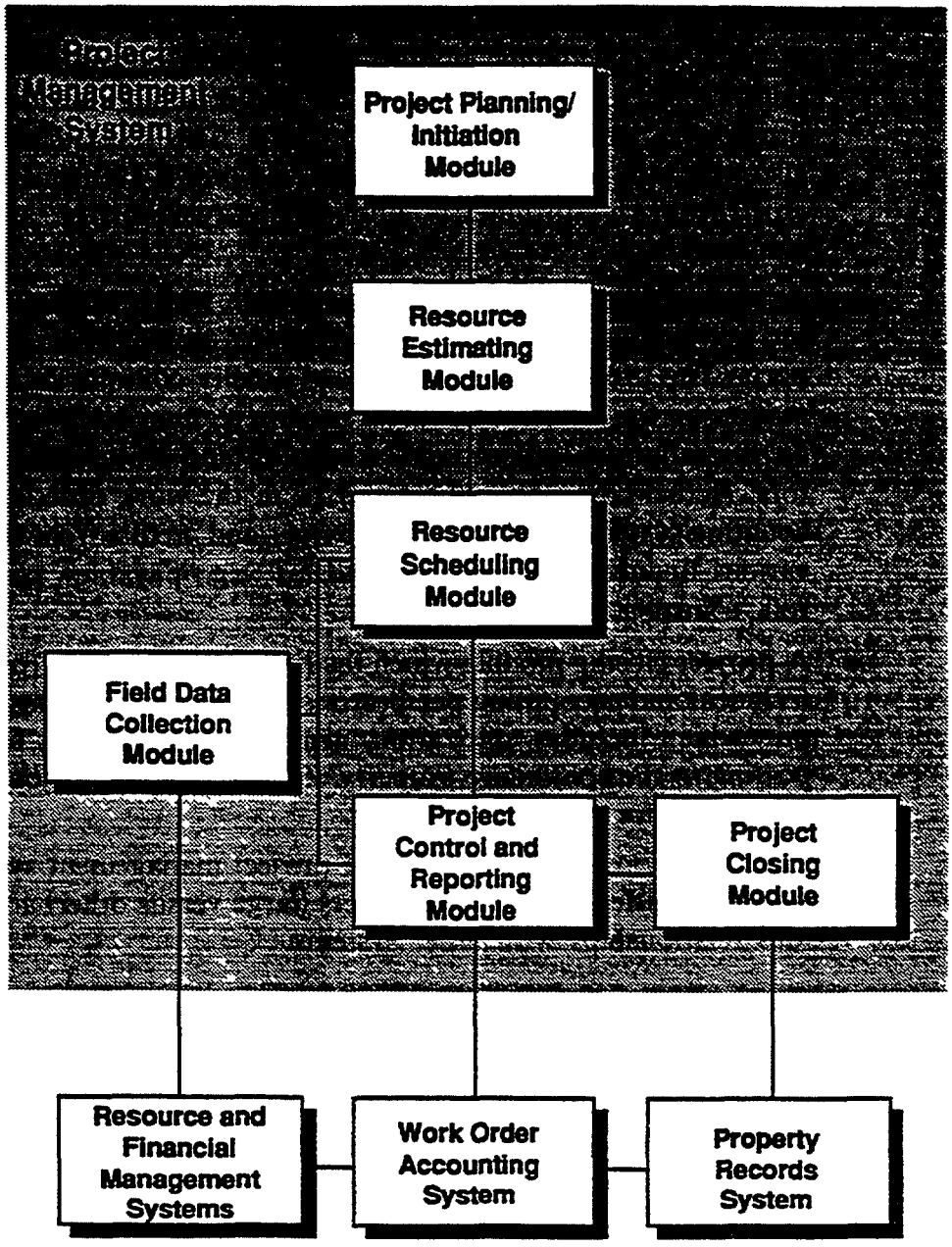

Figure 16-4

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commitment against the project as soon as the purchase order is issued, and transfers the commitment to actual cost as invoices against the purchase orders are processed

The WBS typically has several (or many) levels related hierarchically Budgets are at higher levels in the WBS and represent agreements on the cost of major project components or the whole project Estimates may be prepared for any WBS level A high level budget may be broken out into sets of estimates, which may or may not total to the amount of the budget Actual costs may be collected and reported at the level of an estimate or budget, or at a lower, more detailed level, to provide for cost analysis Cost information may relate to a schedule at an appropriate level of detail in the WBS, to facilitate expenditure forecasting and time phasing of resource needs Cost/schedule integration has been a controversial topic in project management for many years because it can be quite difficult to achieve on large projects

Figure 16–5

Work Breakdown Structure Coding Example
Power Generation Plant Construction
Turbo-Generator Pedestal

WBS Code						Plant Component Description
LIAB					—	Turbine Block
LIAB2					—	Turbine
LIAB2PD					—	Pedestal
LIAB2PD	—	1408			—	Re-Steel
LIAB2PD	—	1408	—	071	—	Rebar
LIAB2PD	—	1408	—	051	—	Labor
LIAB2PD	—	1408	—	090	—	Other
LIAB2PD	—	1428			—	Forms
LIAB2PD	—	1428	—	051	—	Labor
LIAB2PD	—	1428	—	090	—	Other
LIAB2PD	—	1448			—	Concrete in Place
LIAB2PD	—	1448	—	010	—	Eng'r
LIAB2PD	—	1448	—	051	—	Labor
LIAB2PD	—	1448	—	071	—	Concrete, C Y
LIAB2PD	—	1448	—	090	—	Other
LIAB2PD	—	1476			—	Grouting
LIAB2PD	—	1476	—	051	—	Labor
LIAB2PD	—	1476	—	071	—	Grout, C Y
LIAB2PD	—	1476	—	090	—	Other
LIAB2PD	—	1501			—	Embeds
LIAB2PD	—	1501	—	051	—	Labor
LIAB2PD	—	1501	—	071	—	Material
LIAB2PD	—	1501	—	090	—	Other

(Summary levels underlined)

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[4] Projects Other Than M jor Construction Projects

While projects other than major construction projects are smaller in scope than those previously discussed, they represent a large number of individual projects This category includes transmission, distribution, and general plant capital projects which are usually included in the construction budget, as well as noncapital-type projects which include major maintenance work and special projects Special projects are any nonconstruction efforts for which project cost reporting helps monitor or account for costs Examples of special projects are

(1) major computer system development efforts,

(2) company-wide business process improvement campaigns, and

(3) rate cases

These projects do not require the detailed reporting described for large projects and usually are not divided into work packages They are, however, subdivided into smaller subprojects to facilitate assignment to, and/or control by, different organizational entities Therefore, an effective system has the ability to report cost at the subproject level and to summarize these costs up a hierarchical chain to the controlling project

Frequently, many organizational units (responsibility centers) perform work on an individual project For example, several divisions or districts may perform work on a distribution blanket work order The engineer responsible for the work order must know who worked on the job Consequently, the identification of the responsibility center doing the work is an important feature included in a project cost reporting system The ability to report the resources (cost elements) expended by each responsibility center is also necessary Project reporting system capabilities are also designed with "plant accounting" requirements in mind, so that the project records are maintained in a manner which allows for automated closing of work in progress to plant in service Project estimates may be developed to facilitate their use in analyzing actual cost and allocation overheads

A large portion of a utility field organization's work and funds is devoted to constructing and maintaining distribution plants Most of the field organization's individual jobs are relatively small in scope, elapsed time, and cost Thousands of these jobs per year, however, add up to a large expenditure and they, therefore, must be included in the budget Generally blanket work orders are used Blanket work

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orders provide an authorized amount of money for a type of work (e g , new underground residential services in a particular region)

A work management system is a mechanism to plan and control (1) the jobs done under the scope of blanket work orders, and (2) larger distribution construction activities that use work orders A work management system performs many of a project management system's functions and adapts them to the scale of the work being performed Important management system functions are described below

Job initiation This function captures the information needed to define and identify an individual job Much of this information comes from the customer information system

Estimating Estimating uses standards and job-specific information to identify the materials needed for the job and to estimate the amount of labor needed Company or contractor crews may provide the labor The standards used may be "compatible units" (e g., a 30-foot wooden pole with all typical fittings) The "compatible unit" is defined so that while it is useful to engineering personnel for defining and estimating the work to be done, it also makes sense to the field people who perform the work, and it directly relates to a retirement unit that the plant accountants will record in the continuing property records

Scheduling This function is used to determine when a job will be completed It recognizes the required in-service date, the availability of the appropriate type of crew, and any constraining factors, such as coordination with highway work

Job control Job control involves monitoring the jobs' physical completion

Job closing Job closing involves collecting 'as-built" information on the distribution plant actually installed and comparing it to the estimate to identify significant discrepancies needing follow-up This function may also include unitization (using job data to calculate the cost of each retirement unit installed and posting that cost to the continuing property records) This function may alternatively be found in the plant accounting system

Under the work management system, the work order accounting system generally contains the actual cost of the work being completed The work management system, itself, deals with estimates and physical parameters

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[5] Flow of Data for Project Cost Management and Close-Out

The data used to record and manage the cost of projects and to close them out to property records flows through many systems and processes Figure 16-6 illustrates this flow As projects are performed, actual costs and units of resources used (e g , payroll hours, materials issues, contractor hours) that are captured by, or originate in, several systems are passed to a work order accounting system (or function within an integrated financial system) Actual payroll and contractor hours and, in some cases, other quantity data, may also be passed to the project or work management system Summary journal entries update control accounts, such as construction work in progress (account 107), in the general ledger When a job is physically complete, field data collection systems notify the work management system and the work order accounting system of physical completion Field data collection processes also capture the actual quantities of plant installed in terms of the units specified in the job order These units will usually be compatible units or retirement units

When the accounting department determines that all charges applying to a job or work order have been recorded, the job is analyzed for discrepancies between estimated and actual compatible units installed, and between estimated and actual units of materials used Once discrepancies have been resolved, the work order is developed from the many individual work orders and the units and costs are posted to the continuing property records system Summary entries update control accounts in the general ledger The following sections in this chapter describe other systems involved in this flow

§ 16 08 Financial Models

Planning for a utility company's future is, of course, among the most important functions performed by those responsible for an enterprise's success Because utilities are profit motivated, much of their planning will be financially directed In fact, no corporate plan could be considered complete without a financial plan This is especially true for the utility industry because of its capital-intensive nature

[1] Financial Planning Models

A utility's financial plan brings together the company's earnings, cash flows, and financing requirements Today, many utilities employ computerized models to assist the financial planning process A

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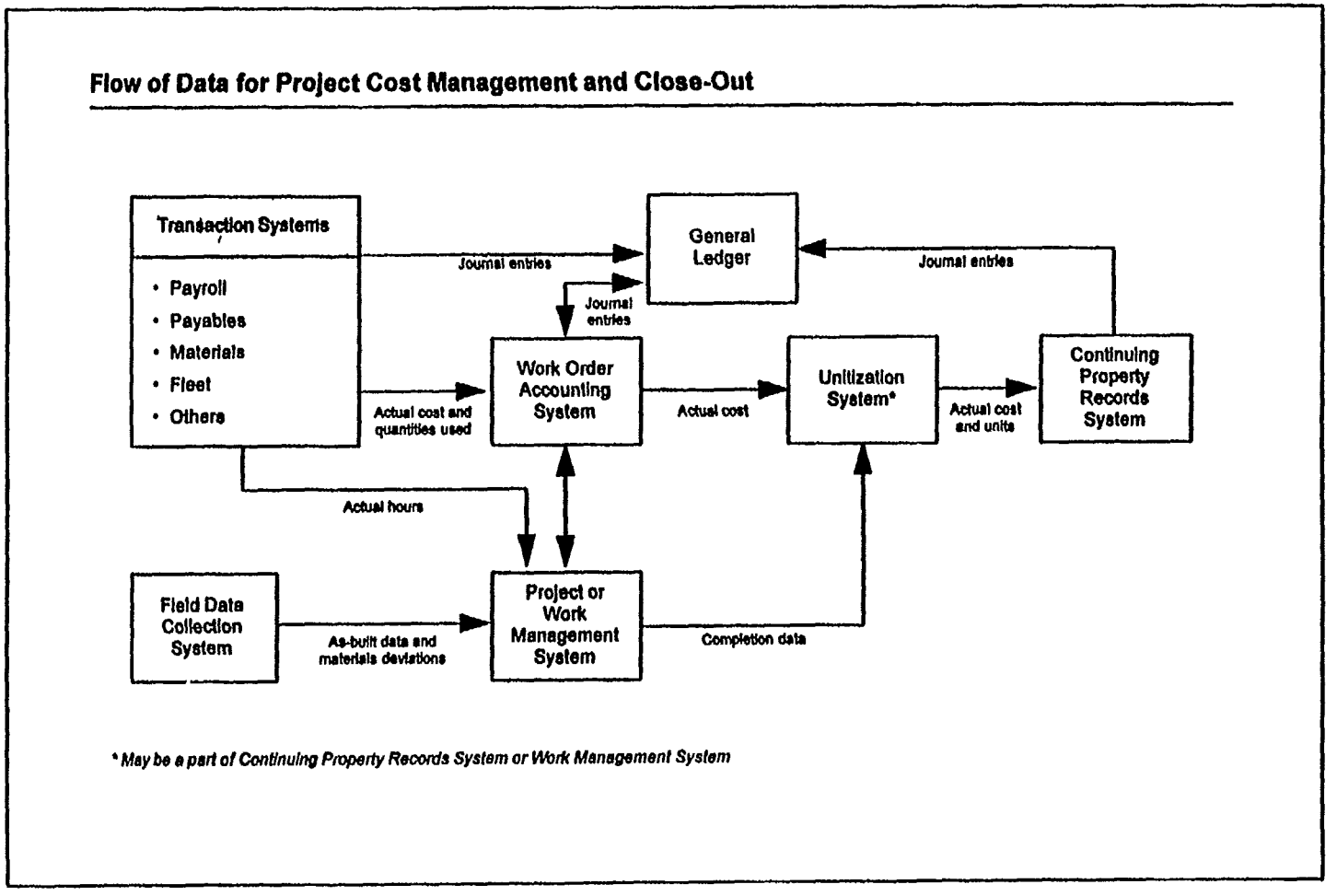

Figure 16-6

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comprehensive and effective financial planning model can help with the following types of utility needs

(1) rate case planning—

(a) identifying changes in revenue requirements,

(b) determining earnings composition,

(c) evaluating the impact of various rate case scenarios,

(2) budgeting—

(a) evaluating alternative capital expenditure programs,

(b) translating rate and revenue scenarios to budget impacts,

(3) treasury planning—

(a) capital structure (debt/equity) planning,

(b) lease/purchase analysis,

(c) covenant compliance (financial ratios),

(4) operational planning—

(a) analysis of the financial impact of changes in costs,

(5) tax planning

(a) analysis of the income tax effects of alternative depreciation methods and rates for different classes of property,

(b) analysis of tax loss carryforwards/carrybacks and investment tax credits,

(6) long-term financial planning—

(a) analysis of the effect of long-term trends in revenues and expenses,

(b) risk analysis of resource additions

In many cases, a utility's corporate model is not a single model but a group of different models integrated in varying degrees, with the output of one model serving as input to another Corporate models may be composed of multiple smaller models for several reasons First, utilities face diverse modeling problems that require a variety of models to deal with the different components at appropriate levels of detail Trying to use a single model to deal with problems as diverse as tax planning and revenue forecasting can be quite difficult These problems can be handled more effectively with several smaller models Second, the cost of developing and operating a single large model can

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be prohibitive and, in many cases, pointless when the problem at hand is very specific Third, the time horizons of different modeling problems is such that different models are needed For example, a model used for planning plant capacity additions should have a much longer time horizon (ten to 30 years) than a budget model (one to two years) or tax model (one to five years)

[2] Examples of Financial Model Applications

The use of a financial model is demonstrated by the following examples for rate making, corporate budgeting, and financing

[a] Rate-Making Application

Increasingly, regulatory commissions are allowing companies at least a portion of construction work in progress (CWIP) in the rate base A model of the nature discussed above can be useful to the utility in supporting this position The model could calculate the utility's construction expenditures, operating revenues and expenses, dividends, and financing These calculations would in turn indicate the amount of CWIP and cash flow The company could then perform "what if" tests concerning CWIP in the rate base (that is, what would happen to rates, revenues, and return) if the commission permitted the company, for example, 30 percent of CWIP in the rate base Basically, the model would perform the following steps

(1) adjust the rate base for the inclusion of CWIP,

(2) adjust the revenue requirement (due to the increase in the rate base) and the rates,

(3) adjust the projection in demand (due to the increase in rates), and

(4) adjust the projection of revenues, expenses, and cash flow

This model can then be used during actual rate proceedings Counterproposals for a lower percentage of CWIP in the rate base may be offered during the hearings, and the company can then run the model to produce that plan's results

[b] Capital Budgeting

Financial planning models can also be quite useful for a utility in the area of capital budgeting, since this process is one of the most important planning problems in the utility industry A capital budget

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model can support planners in developing good cash flow data for evaluating project financing requirements There can be significant differences between budgeted capital accounting expenditures and actual construction cash outlays These differences can be caused by items such as noncash charges for allowance for funds used during construction (AFUDC), allocated overheads, and clearing account charges In addition, actual payments for labor and material can lag behind accounting accruals Projections based on different circumstances or the use of ranges of expenditures support realistic approaches to capital budgeting

A utility can also use a financial planning model of the type described above to evaluate alternative cost control programs For example, alternative equipment packages might be developed to cut operating costs Data concerning the proposed operating savings and construction costs can be input into the computer The model then generates earnings and cash flow data associated with each proposal The results can be analyzed, and the best alternative selected.

An emerging capital budgeting problem for public utilities, and one in which modeling systems can be quite useful, is the evaluation of conservation programs Increasingly, many public utilities are evaluating programs designed to reduce demand rather than to increase production through expansion of existing plants or building new ones In this situation, the user can input various assumptions about both the investment in equipment and the operating costs associated with a proposed conservation program Other assumptions can then be input to the model such as

(1) reduction in demand by class if the program were implemented, and

(2) costs of building additional generating capacity

The model then produces projections of costs and cash flows These projections can be converted into a cost per unit of energy saved which is then compared with the cost per unit of energy for new capacity Based upon this analysis, management can better decide whether to undertake the conservation program or to build additional capacity

[c] Operating Budget

Financial models are also quite useful to a public utility in evaluating its operating budgets A financial model can be used to project

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both income and cash flow under various alternatives proposed during the budgeting cycle For example, a model can be used to project key expense items for budget preparation While a number of financial modeling systems are designed to develop these projections, an effective system should incorporate two features First, the system should be integrated with the accounting and budgeting system to make forecast preparation easier If integrated, budget and actual data are readily available to put into the model Second, an integral part of the operating budget exercise is the capability to develop a cash flow budget

An effective financial model can be useful in assessing the cash flow implications of budget alternatives This assessment is possible if the model employs the double entry concept and measures both earnings and cash flows simultaneously With a proper model, a proposed budget can be run through the model, and the related cash flows assessed

[d] Outside Financing

A major use of a financial modeling system is to evaluate financing alternatives Determining whether to issue debt or equity hinges upon considerations such as expected future cash flow, the tax situation, dividend requirements, stock market prices, and interest rates A transactions-oriented model which can project earnings and cash flows simultaneously is particularly useful for dealing with this problem Cash flow projections are particularly important for deciding whether to issue debt since debt entails fixed payment obligations Furthermore, in planning whether to issue debt, it is important to develop earnings projections to determine whether the utility will be able to satisfy financial ratio covenants in its existing debt indentures Typically, a debt indenture requires a utility to maintain earnings at a level two or more times greater than annual debt interest expense This ratio is also called the "times interest earned" ratio or "coverage" ratio

[e] Financial Analysis of Operations

Utility executives need to know the financial effect of potential changes in operations For example, changes in wage rates and benefits programs can be examined Changes in wages, benefits, and estimated changes in productivity can be put into the model The model

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calculates changes in expenses and cash flows management might then use the output of the model to help during contract negotiations

[f] Risk Analysis

Long-term financial issues are also of paramount concern to utility executives faced with making decisions about the financial effects of adding new resources The recent trend by state commissions to disallow some or all of the costs of new generating resources has dramatically increased the risk of constructing new baseload generation

Many financial modeling languages have Monte-Carlo analysis or other features designed to incorporate risk into the decision-making process Monte-Carlo analysis is particularly insightful in situations in which it is difficult or inappropriate to assign single point estimates to certain variables In this situation, executives estimate a probability distribution for regulatory disallowances The probability distribution characterizes the range of estimated regulatory disallowances The financial model is executed a number of times, using a randomly selected value for regulatory disallowance chosen from the generated resources with cogeneration and/or long-term purchased power contracts

§ 16.09 Customer Information Systems

A public utility customer information system (CIS) supports the entire customer-related process, including service requests, meter activity, billing and receivables, and customer related management information The following sections briefly identify some of the important functions supported by an automated customer information system

[1] On-Line Inquiry and Order Entry

One of the most important CIS functions is providing on-line inquiry and update via a remote network into the customer's master file to obtain historical and current data Utilizing this facility, customer service representatives located in remote or centralized service centers are able to respond quickly to customer requests for service, billing complaints, or other inquiries In addition, the on-line inquiry capability is utilized by credit and collection personnel, by personnel responsible for correcting billing errors, and by others with customer

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accounting administrative responsibilities Most customer information systems include an on-line service order entry capability As customers call in requesting service connections, disconnections, or other services, the order is entered into the computer by the service representative taking the call A copy of the order is automatically printed at a field service location or passed to another system for electronic routing to a service technician's mobile data terminal The computer maintains control of the pending order until a completed transaction is entered and produces "tickler" information periodically on incomplete orders With this feature, the CIS becomes useful to the distribution department for scheduling and control of field service activities

[2] Meter Reading

The customer information system (CIS) provides meter-read information to locate the meter to be read, special instructions or alerts, and historical data designed to assist in the proper reading and recording of the required information Most companies use hand-held devices or remote meter-reading systems that interact with the CIS The route and reading information is downloaded to the hand-held or vehicle-mounted devices After readings are captured, they are uploaded to the CIS

Many systems also edit check the readings against historical usage data, adjusted for current weather conditions This "high-low" or tolerance checking allows verification of the reading in the field or further investigation before billing The same type of processing may also be used to estimate usage if reader is unable to read the meter (or the entire routine)

[3] Billing

The customer information system (CIS) calculates and prints the customer's utility service bill based on usage developed from the meter reading or an estimate and based on appropriate service rate schedules Flat rate charges such as security lighting also are included in the utility service bill

In addition, the customer's bill may include nonutility charges such as repair service, merchandise, equipment rental, leased appliances, collection charges, reconnect charges, and installment payments Many utilities provide level payment or "budget" plans, billing the customer an equal monthly amount based on expected average utility charges

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[4] Accounts Receivable

The customer information system (CIS) maintains the customer's accounts receivable balance and payment history Cash normally is posted to the account on the same day it is received to minimize erroneous late pay penalty charges or inappropriate disconnections for nonpayme- CIS automatically generates ledger entries to support in. -al cc ol and verification of cash deposits

[5] Collection Action

The customer information system (CIS) automatically identifies cus-omers with past due balances and applies late payment penalties if . owed by company olicy and regulatory authority Disconnection warning documents are printed for mailing to customers with overdue balances exceeding a specified amount, and a notice of customers to be disconnected is prepared for field personnel when the grace period elapses

After disconnection for nonpayment, many utilities continue efforts to collect ba -ces due These efforts typically involve ar in-house collection staff that attempts to locate the customers to r- olve the outstanding balances Once delinquent customers are located, they are encouraged to resolve their unpaid bills through collection letters, telephone calls, pa ent arrangements, garnishment of wages, litigatior and other le. methods An additional common practice is to tra. r the unpaic alance to another service address that is used by the inquent customer Service will be subsequently disconnected at the new location if the previous balance is not resolved

After in-house lection efforts are determined to be unsuccessful, unpaid balances a requently referred to outside collection agencies, credit bureaus, or attorneys for further action Outside firms are valuable if the utility does not have a sophisticated in-house collection system and experienced collection personnel Collection agencies in particular are useful in locating and collecting from customers who have moved outside the utility's service area

[6] Deposits

In ormatior tive to deposits collected from customers when they apply for ser is maintained in the customer information system (CIS) The CIS automatically computes the interest due the customer

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on the deposit Frequently, the system will refund the deposit automatically, by check or by application to bills, if the customer's payment history warrants Conversely, the CIS will automatically bill the customer for an additional deposit, based on preprogramed criteria, if payment history is poor When a customer voluntarily discontinues service, the CIS automatically applies the deposit (with interest) to the final bill, producing a check if a refundable balance results

Unless prohibited by regulatory authority, deposit amounts can vary to reflect anticipated usage at individual locations The CIS assists with determining deposit amounts by analyzing actual prior usage at the service address, determining the typical usage for the size and type of structure at which service will be provided, estimating consumption on the basis of the appliances and other energy consuming devices that will be used, and similar methods

[7] Revenue Reporting

The customer information system (CIS) provides data that classify billed revenue in a number of ways, for example, by customer class (residential, commercial, industrial, etc), rate class (general service, space heating, water heating, etc), town, business class, industry class, etc The system produces reports, by the various classifications, which include statistical information, such as consumption per customer or revenue per customer, as well as consumption and revenue totals The data is automatically passed to the corporate financial information system so that revenue accounts are updated

[8] Support of Rate Case Preparation

Preparation of rate case documents for submission in conjunction with a request for rate relief (increase) generally requires development of test period revenue Basically, this involves "billing" actual consumption for a prior year under proposed new rate schedules to determine the percent of increased revenue realization The ability to develop an accurate rate case in a reasonable period of time can be dependent on the type of historic billing data stored by the customer information system (CIS) and on the ability to obtain and process that data effectively

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[9] Refund of Amounts Collected Under Bond and Later Disallowed by Regulatory Authority

Many utilities are allowed to implement rate increases before approval by regulatory authority, with the stipulation that if all or part of the increase is disapproved, a refund will be made to customers In cases of this disapproval, the customer information system (CIS) must be capable of recalculating prior bills, determining the excess charge amount, and refunding that amount to the customer, either by application to subsequent bills or by check In some cases, refunds have been necessary for periods in excess of a year

[10] Management Reporting

Public utility service areas frequently are very large, so that field operations are necessarily decentralized District offices perform such commercial field services as meter reading, cashiering, collection of overdue accounts, connection and disconnection of service, and final billing and bill correction, as well as line maintenance, tree trimming, and other plant maintenance services not directly related to customer services In this type of environment, it is difficult to exercise senior management control without a viable automated performance reporting capability A carefully designed customer information system (CIS) provides this capability

The CIS should also contain other information from which report families useful to management can be derived These might include

(1) Aged accounts receivable by district or local office area, or other appropriate responsibility center

(2) Billing adjustments, including numbers of accounts and amounts of dollars, by customer service representative initiating the transaction, with summaries provided for successive levels of supervision and management

(3) Theft, or suspected theft, of service reported by meter readers or other field personnel for comparison with unbilled consumption statistics by local office area or other responsibility center

(4) Meter reader performance statistics (e g , number of meters, skips, and incorrect readings) by individual meter reader, with summaries provided for successive levels of supervision and management

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§ 16.10 Materials Management System

A materials management system typically encompasses those functions that concern the ordering, control, and accounting for materials required in a utility's day-to-day operations An effective system provides the means for reducing the investment in materials and supplies inventory while achieving a level of service consistent with management directives In addition, the system reduces the administrative costs of controlling inventory Thus, the system should cut working capital and operating costs and increase the productivity of construction and operating personnel

The functions of a materials management system can be logically grouped within four basic components, which are discussed in the following sections

- requisitioning and purchasing,
- inventory control,
- inventory forecast and reordering, and
- materials and supplies accounting

Software packages usually provide an accounts payable module that is closely coupled to the purchasing and stores function

[1] Requisitioning and Purchasing

The requisitioning and purchasing module of a materials management system supports the preparation of a requisition and its conversion into a purchase order People throughout a company may initiate a requisition on-line (or by using a document) to denote the items or services they need, the date needed, delivery location, any unique technical or logistics requirements, and accounts or work orders to be charged The system may support electronic routing and approval of the requisition The nature and/or estimated value of the requisitioned items or services may require that bids be solicited and evaluated A materials management system may support the bidding process, including automatic selection of suppliers to receive invitations to bid based on supplier preference or dispersion practices, minority procurement programs, and/or geographic factors

The system then supports the conversion of requisitions into purchase orders, including vendor identification, pricing, attachment of standard specifications, and automatic routing for information and

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expediting purposes Electronic data interchange (EDI) technology may be used to transmit purchase order data to suppliers

[2] Inventory Control

The inventory control module supports receiving, issuing, and returns of stock items as well as physical management of inventories at stock locations or outside locations The system supplies purchase order data to support on-line receiving and incoming inspection The receiving data (including rejects and returns to suppliers) is entered on-line to update purchase order status and on-hand inventory quantities The system provides information on where to place items in the storeroom

This module also processes stock issues (which may be captured at storeroom or field locations) requisitioned by people throughout the company or generated by other information systems such as a work management system For issues requested in advance, the system may generate pick lists Pick lists let storeroom personnel know where the items to be issued are located and the quantities needed The system records the quantities issued and the account number or work order to be charged

Some items may be sent out to other companies for repair The inventory control module records these movements Utilities have part of their inventory, consisting mainly of small value items, on service trucks Once the truck stock is issued to a truck, it is no longer specifically tracked Work management systems will support the determination of approximate usage on work orders and regular physical inventories help provide adequate control

This module also supports the planning, recording, and reconciliation of physical inventories This is usually done on a cycle basis It also provides reporting of inventory balances, slow moving and potentially excess stocks, and various analytical reports, such as activity-based costing (ABC) analysis of inventory composition

[3] Inventory Forecast and Reordering

To generate purchase orders automatically, it is necessary to develop the following data and ordering criteria

(1) Forecasted usage, which is needed to predict demand for material in calculating order quantities There are many types

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of demand forecasting methods Most use a number of periods of historical usage data Forecasting logic generates forecast of future demand (for one or several future periods) using various weighting factors and statistical models The forecast is used along with known project demands, lead time, and quantity factors to develop suggested order quantities The forecast may be by group or by line item of quantity and dollars A group forecast may be expanded to the unit level, based on historical relationships within that group

(2) Lead time, which is a prime factor in determining the reorder point Some of the considerations in the development of accurate lead times are the days necessary for

(a) recognizing the need for an item,

(b) processing the required purchase requisition,

(c) delivering the order to the supplier; and

(d) delivering materials to the storeroom

(3) On-hand balance This is the quantity currently in the store rooms It includes reserved stock not released from stores

(4) On-order data which should reflect all open purchase orders written for each item The amounts are added to the on-hand balance for purposes of reordering

(5) Stock reservation, which earmarks items intended for use with a particular project This information is used to decrease the on-hand balance for purposes of reordering

(6) Safety stock This is maintained to cover variances in the usage and lead time forecasts

(7) Order quantity This is calculated on the basis of both independent and dependent demand characteristics Independent demand is not related to the demand for other items Order quantities for independent demand items are calculated using lot-for-lot or economic order quantity (EOQ) EOQ balances the cost of carrying the inventory against the cost of processing or manufacturing an order Order quantities for dependent demand items are calculated using least total cost, part period balancing, and other lot sizing techniques Independent and dependent demand order quantities should be calculated separately and then combined if there are similar orders.

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(8) Reorder point, which is the level of inventory on hand and on order, less reserved stock and short term forecasted usage, that will trigger a replenishment order The reorder point is calculated as forecasted usage during replenishment lead time plus safety stock Order requirements for dependent demand items are generated by the requirement date for the end item

(9) Vendor selection For this information, the line item number is tied to a vendor number or series of numbers For items included under "blanket" orders, suppliers are known before the issuance of individual purchase orders Before an order for items, other than blanket items, is issued, vendors must be selected based upon analyses and comparisons of past delivery and quality of performance for the particular commodity

Because of demand patterns and economics, many items in a utility's inventory are reordered using high/low inventory quantity parameters rather than by demand forecasting

[4] Materials and Supplies Accounting

The materials and supplies accounting component calculates unit prices for the material items, prices the material issues and returns, and maintains an updated inventory balance The materials and supplies charges and credits are distributed to the appropriate operating and maintenance accounts and to construction work orders in the operating expense reporting systems or construction work in progress system

The materials management system interfaces with the accounts payable system (discussed in section 16 12) providing the mechanism for accurately checking material receipts with the purchase orders and invoices on a timely basis As invoices are received from suppliers and material receipts are received from storerooms, they are entered into the system and matched internally with the corresponding purchase orders Item values are calculated, cash discounts are deducted, purchase order files are updated, direct charge material items are loaded with stores expense, and net item values are calculated and distributed to accounts or work orders

§ 16 11 Payroll/Personnel System

A payroll/personnel system typically encompasses those functions required to pay employees, to maintain personnel records, and to assist

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in the allocation of the costs incurred, both actual and accrued, by each employee to the proper organizational unit and account distribution Payroll/personnel systems operating in a utility setting tend to be more complex than the typical corporate systems because of the large number of remote work locations, the complex distribution of expenditures to appropriate accounts and work orders, and the complexities of some union contracts

Specifically, a payroll/personnel system should support the functions of·

(1) employee compensation and compensation administration,

(2) applicant processing,

(3) human resources management,

(4) position control,

(5) benefits administration,

(6) labor cost distribution,

(7) payroll tax accounting; and

(8) time entry

These functions are discussed in the following sections

[1] Employee Compensation

The employee compensation function encompasses the maintenance of time and attendance and the computation of pay Pay computation includes the calculation of gross pay, which incorporates regular earnings, overtime earnings, payments for call-outs and hazardous duty, shift payments, and adjustments to earnings In addition, pay computation includes the calculation of net pay, including the withholding of federal, state, and local taxes and the calculation of other involuntary and voluntary deductions

The system computes employer fringe benefit payments such as insurance, pension, workman's compensation, and unemployment insurance The employee compensation function also includes the maintenance of employee earnings history, the actual payments to employees, and the reconciliation of each processed payroll

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[2] Applicant Processing

The applicant processing function can facilitate a job posting policy, provide valuable information to company management concerning applicant qualifications, and maintain information on letters of reference and physical examination results

Additionally, historical information can be maintained on all applicants, whether accepted or rejected The data can be used to provide management with comparative profiles of applicants for use in monitoring of diversity goals and labor costs and for use in work force planning

[3] Human Resources Management

The human resources management function often includes the following processes

- authorizing and establishing the employee on the payroll/ personnel files,
- maintaining performance evaluation data, and
- maintaining traditional personnel data (including current address, employee service records, personal injury and accident records, job history, education, and training)

The function may also include administration of company service award programs, tracking and reporting of employee turnover, and maintenance of job classifications and job codes The human resources management function may also encompass the maintenance of data required by regulatory agencies, such as the Occupational Safety and Health Administration (OSHA) and the Equal Employment Opportunity Commission (EEOC)

[4] Position Control

The position control function assists in manag g positions in accordance with salary scales and budgets It provides assistance in budgeting by providing a what-if tool for personnel costs and can provide management with status reports on each position, including whether the position is open or filled The salary range for the position, the date(s) that projected positions will become available, and the budget status for each position can also be provided

[5] Benefits Administration

The benefits administration function is responsible for administering paid benefits, such as group life, health, and accident insurance, pension plans, workmen's compensation, and other company-maintained employee benefits In addition, the system maintains the amounts withheld from each employee for voluntary deductions, calculates the associated company contribution where applicable, and provides a detail and summary report of these contributions This information is used to calculate the payments required to outside insurers, trustees, etc , and is also used to prepare necessary regulatory reports

[6] Labor Cost Distribution

The distribution of labor costs involves the assignment of direct costs and allocation of the indirect costs to the proper accounts, work orders, and cost centers receiving the benefits of the expended labor Labor distribution within a utility is an especially critical function It is extremely important to allocate labor costs accurately among various capital projects or expense accounts due to the impact these categories have on the rate-making process

Additionally, the labor distribution function is necessary to maintain the accounting records, to facilitate management reporting, and to conform with regulatory reporting requirements

[7] Payroll Tax Accounting

The system should provide all information that is required for federal, state, and local tax filings and reports The system should maintain detailed information about all taxable and nontaxable earnings, should calculate and maintain information related to taxes withheld for federal income tax and social security (both employee and employer), and should segregate and maintain information pertaining to income taxes withheld for each state and local agency The system should also be able to support and maintain the information necessary for the company to report federal unemployment insurance, employer state unemployment insurance, and employee disability taxes

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[8] Time Entry

The time entry module allows time orked by individual employees and crews to be entered on-line (The ame module may capture time worked by contractor personnel, for use in other systems) Employee or crew time worked is entered and coded to show the type of time worked (such as regular time, overtime, call-out, and time worked out of grade) and the accounts, activities, or work orders to which the time applies The module may validate the classification of time reported against the union contracts It may also monitor the distribution of overtime signed by area, such as seniority or classification

Time captured by the time entry module may be reported and entered daily or less frequently The time data is then passed to the payroll module for calculation of payroll dollars and may be passed to work management or other systems that use hours worked data for monitoring the status and cost of work orders and for productivity measurement In some cases, the time capture module is actually part of the work management system The time entry module may also capture vehicle or equipment usage and job completion data

Salaried personnel may be on a fixed distribution of labor cost Generally, in this case, the utility calculates payroll distribution automatically, using a data base of each employee's time to accounts and work orders The employee need only enter overrides (reflecting special projects, temporary assignments, holiday/vacation/illness, or other paid time not worked) to the fixed or standard distribution

§ 16.12 Accounts Payable System

An accounts payable system is designed to control invoice flow, capture approval of invoices for payment, accrue liabilities, provide cost information, pay invoices in a timely manner, and provide proper accounting entries to the general ledger and subsidiary ledgers

Utility companies traditionally have many people who purchase a large volume of capital and stores inventory items This procurement effort requires system that can provide effective control A good accounts paya system should be able to control transactions from the time an invoice is received until the time a check clears the bank This system traditionally interfaces with the financial accounting, cost accounting, and materials management systems

The significant functions within the accounts payable system include

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- document input and matching,
- cash management and control,
- maintenance of a vendor master file, and
- accounting control

[1] Document Input and Matching

The documents traditionally used for procurement are the purchase order or contract, the receiving document, and the vendor invoice The payables system interacts with the materials management system to ensure that all three documents are matched before payment is authorized Additionally, the system compares the unit prices on the purchase order and on the vendor invoice(s) These prices must be within the tolerances specified by management, or they will be flagged for review

The purchase order, receiving document, and invoice all contain basic data critical to the functioning of the accounts payable system All materials and supplies received should be supported by receiving documents before payment is authorized on an invoice At the very least, the receiving document should contain a description of the items received, the line item stock number, the quantity received, and the associated purchase order number Invoices can generally be classified into one of three categories

(1) invoices with purchase orders and receiving documents,

(2) invoices without purchase orders and receiving documents, and

(3) miscellaneous invoices

Invoices received that are not matched with authorized purchase orders or receiving documents (or both) require special handling, as defined by company policy These items may be company credit card charges, minor repair orders, miscellaneous office supplies, employee expense accounts, etc Generally, some form of pay-authorization document with appropriate signatures and account distribution is required before payment can be made

[2] Cash Management and Control

An effective accounts payable system provides for cash requirements forecasting, schedules cash disbursements as desired by management, automatically schedules payments for vendor invoices

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incorporating discounts in the time frame required, and identifies and withholds duplicate payments In addition, the system should produce and print the checks payable to vendors It may also interface with electronic data interchange (EDI) technology for transmission of payments

[3] Maintenance of Vendor Master File

A vendor master file should be maintained It should include such information as vendor number, name, address, purchasing history, and financial rating The accounts payable system should not permit the preparation of a check for any vendor that is not on the vendor master file Maintenance transactions should add new vendors, modify existing vendor information, and delete vendors The maintenance of the vendor file must be coordinated with (or controlled by) the purchasing function

[4] Accounting Control

Accounting control is the responsibility of company management Establishment and maintenance of good accounting control requires that management set up and provide for

(1) a plan of organization that provides for appropriate segregation of duties and responsibilities,

(2) a system of authorizations and procedures adequate to provide control over assets, and

(3) properly trained and qualified personnel

§ 16.13 Fleet Management Information System

The transportation function provides the necessary transportation and equipment for the utility's administrative, construction, operation, and maintenance activities The fleet normally consists of passenger vehicles, light- and heavy-duty trucks, and specialty equipment Typically, a transportation information system maintains detailed records on each vehicle and piece of equipment regardless of whether it is leased or owned by the utility Specific information is first entered into the system whenever the vehicle or equipment is acquired Once placed in service, the system tracks its day-to-day operation, schedules preventive maintenance and license renewal activities, maintains repair history data, and forwards accounting information to the financial information system

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[1] Fleet Inventory

One of the major system functions is to record all data related to additions and deletions to the fleet inventory Furthermore, since the system maintains individual vehicle and equipment records, it is the logical place to maintain accounting information concerning both owned and leased fleet items Original cost information is entered when the item is purchased and placed in service as well as the description and responsible cost center for each fleet item When an item is disposed of, retirement information is processed in a similar manner

Under an integrated system concept, addition and retirement information flows to the financial accounting system for proper accounting treatment and financial reporting according to the utility's plant in service record and lease accounting practices Lease payment information is initiated by the transportation information system and is forwarded to the accounting information system Furthermore, information maintained by the system is used for depreciation and insurance analysis

[2] Fleet Maintenance

The fleet maintenance function records all data related to the maintenance and repair of fleet items When vehicle operators identify problems requiring repair procedures, a repair order is normally prepared Actual labor and spare parts costs are charged to the repair order A history of repairs and the associated costs is retained for fleet performance and budget analysis In addition, the system maintains data on preventive maintenance and state inspection requirements in order to schedule these activities and report noncompliance on an exception basis The system may also maintain inventory records for spare parts

[3] Operating Cost Distribution

From a systems integration standpoint, cost distribution is the key function of the transportation management system The operating costs of vehicles and equipment are distributed to construction work in progress and appropriate operations and maintenance general ledger accounts for reporting through the financial information system The actual operating costs of vehicles are accumulated by each class of vehicle and charged to a clearing account Examples of operating costs

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are the costs of gasoline, oil, and the labor and materials associated with repairs

Some utilities compute an estimated distribution rate per mile or per hour for each class of vehicle on the basis of historical operating costs and use this rate to redistribute, or "clear," the clearing account Typically, the distribution rate is adjusted periodically to reflect the over- or under-clearing that occurs at the end of the accounting period

As vehicles are used in construction or maintenance projects, such as construction of a new electric distribution substation or repairs to a deteriorating natural gas main, time or mileage associated with the project is reported on specialized transportation management system data input documents, which allow for recording of the necessary accounting distribution codes The transportation management system then prices out the mileage or hours and passes the charge on to the financial information system, along with the required accounting distribution codes

As an alternative to entering vehicle usage charges for projects into the transportation management system, some utilities capture the data on time reports for entry into the payroll/personnel system The payroll/personnel system calculates the cost to be distributed to the major projects and work in progress systems on the basis of predetermined rates When a project is completed and closed, these costs are further distributed either to the appropriate plant accounts or to operating and maintenance expense accounts by cost center

Vehicle and equipment usage and cost distribution for nonproject-related activities are accounted for through the use of "trip ticket" documents entered into the transportation information system The system then forwards the distributed costs to the appropriate operations and maintenance accounts by cost center in essentially the same manner as project costs are processed

§ 16.14 Journal Entry System

A journal entry system may be established as a self-contained "feeder" system or it may function as a "direct entry" system This feeder system provides a single-source or journal entry distribution listing that summarizes all details by account or work order This approach simplifies the control process by accomplishing the balancing function before combining these source transactions with transactions from all other sources

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If the ultimate posting medium (that is, the general ledger or work-in-progress ledger) is designed to reflect detailed journal entry charges, however, it may be more expeditious to charge each transaction directly to the ledger The balancing function, in this case, is the responsibility of the posting module of the applicable system

§ 16.15 Continuing Property Records System

The continuing property records (CPR) system maintains asset cost records and serves as a detailed subledger to several general ledger accounts (e g , account 101, plant in service) Two important elements of asset recordkeeping are vintage and retirement units Vintage is the date (or year) in which the property is placed in service, the work order for that property may close quite some time after the plant is declared in service Retirement units are pieces of property which are carefully defined to indicate what is or is not included in the unit For example, a 50-foot pole may be a retirement unit, including any crossarms, downguys and anchors, and minor hardware When the pole is taken out of service, the whole unit, as defined, is considered retired and the full unitized cost of that pole is taken out of the plant-in-service balance Removal or replacement of a part of the unit, for example, a downguy or brace, is considered a maintenance expense and does not affect the asset value When a work order is closed, its total cost is unitized, that is, assigned to the various units of property that were installed on that work order Some of the cost is directly associable with the various retirement units installed on the work order while other costs are allocated to the retirement units

The CPR system typically performs these functions

- maintains an electronic catalog of retirement unit definitions, coding, and nomenclature, for use by the CPR system, the work order accounting system, the work management system, and potentially the geographic information system,
- maintains book and tax basis costs for assets at a retirement unit level, by vintage,
- processes addition, retirement, and transfer transactions originating in the work-in-progress accounting system and its work order closing and unitization processing,
- computes book and tax depreciation,

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- generates journal entries for general ledger posting;
- provides reporting of asset values by property tax jurisdiction, in support of filings to taxing authorities,
- provides reporting of insurable and insured property for insurance arrangements and claims,
- provides reporting of specific assets or groups of assets for example, pollution control equipment, to various governmental and regulatory agencies and industry associations,
- prepares property ledgers and various financial and management reports

Some companies have separate systems for tax basis records and calculations

§ 16.16 Plant Maintenance System

Most public utilities maintain large and complex generation, transmission, and distribution facilities Often hundreds of employees and millions of dollars in materials are required to support these facilities Many utilities have implemented facilities or plant maintenance systems (PMSs) that plan, manage, and control the company's maintenance projects The PMS also may interface with other systems (e g , input hours worked to the payroll system, access expense data from the accounts payable system, commitment data from the purchasing system)

§ 16.17 Treasury Management Systems

Treasury management systems are used to manage cash, investments, and short- and long-term debt The systems maintain records of individual accounts and instruments, alert treasury personnel to maturities and actions needed, and may include models to help the utility maximize the net return on its asset and liability portfolio The treasury management systems must keep nonregulated operations activities separate from other subsidiaries In the future, some utilities may need multi-currency capability as they invest in foreign projects

Treasury management systems may be separate systems built with spreadsheets or data bases on PCs, or may be integrated software packages

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§ 16.18 Tax Management Systems

A utility may have several systems in use to support the activities of the tax department The continuing property records system as containing book basis assets, reserves, and depreciation calculations (see § 16 15) The continuing property records system may also contain tax basis records It is more common, however, to use a separate system for tax basis assets, reserves, and depreciation calculations The tax basis property system contains only the level of detail needed for tax purposes (as opposed to the considerable detail necessary for book basis records) A tax basis property system maintains tax basis asset and depreciation reserve records, tracks book-tax basis differences, calculates depreciation and amortization, and performs other record keeping for tax regulations in effect for each vintage The system must also address unique tax requirements of states, cities, or other taxing entities

Tax management systems often record tax accruals and payments and the composition of deferred tax balances for federal and state jurisdictions They may also be able to model taxes under various assumptions about factors such as rates and deferrals Tax management systems may consist of a series of spreadsheets or software packages using similar methods

§ 16 19 Shareholder Records System

A shareholder records system is used to maintain records of securities owners, make dividend payments, manage mailings to shareholders, and handle changes in securities structures such as stock splits The utility company may operate the shareholder records system, or it may outsource part or all of this function

§ 16.20 Data Processing Considerations

[1] Coding

The heart of an integrated financial information system is the design of the accounting codes used to classify and to process data The utility must consider problems that may develop if field personnel must code long, complex accounting data code groups on transaction source documents If this occurs, field personnel often become indifferent toward correct coding

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On the other hand, it must be recognized that management information requirements demand the ability to analyze information from many different perspectives For example, the same costs may be classified for various reporting purposes with account coding that includes

- company and/or business unit,
- responsibility area,
- activity,
- work order;
- expense type, or
- regulatory account (this may be derived from other codes)

Coding may also include location and equipment identification

A large amount of information needs to be coded because most utilities now emphasize activity-based costing and reporting for day-to-day business management These needs do not necessarily mean onerous account coding requirements for field personnel If systems are designed to build the account code instead of merely accepting it, then field personnel only need to enter codes unique to the situation, such as the event type, location, hours expended, and employee number

[2] Timing of the System

Public utility financial information systems generally are designed to report costs based on the traditional monthly accounting cycle Management's increasing need to control cash flow and monitor expenses requires more frequent interim financial information Timing of the system can become a problem, because the individual feeder systems usually close on different days For example, payroll may close on the last Friday of the month, accounts payable on the 25th calendar day of the month, and customer billing on the 21st work day of the month If the reporting system is run before the closing of a feeder system, transaction activity for the month will not be reported accurately

For these reasons, to be effective, a system must be able to provide information on an "as needed" basis The system should be able to process accounting data from selected feeder systems on a shorter cycle, even daily This capability allows for interim project reports

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containing current charges, with full cost data reported monthly Management may require on-line access to certain levels of accounts to monitor revenue and expenses, make expenditure decisions, and review divisions' revenue streams. Those developing a financial information system with interim reporting capabilities, must be careful to include adequate internal system controls to prevent confusion over what data have been processed

[3] Front End Validation

An efficient financial information system validates an accounting charge when the transaction first enters the automated system ("front end" validation) Front end validation ensures that numerous transactions are not rejected at the end of the accounting cycle because of coding errors, resulting in frantic efforts to correct data so that financial reports can be produced on schedule Each of the feeder systems, therefore, should validate transactions as they are entered Because accounting codes on transactions entering the various feeder systems are standard, all feeder systems should use standard validation tables This integrated approach to data validation greatly reduces program maintenance time and ensures that data validation by the feeder systems is synchronized

Front end validation should allow for data to be corrected immediately The most effective approach is on-line, interactive correction With on-line, interactive correction, the validation routine processes data when it is entered and returns a message to the entry station displaying errors found and the action required to correct them The operator corrects the data using help screens or other references and the validation routine again processes the transaction This sequence is repeated until the transaction passes validation and is accepted and stored in a data file

[4] Ease of Modification

The utility should consider ease of modification when designing an information system A financial information system almost certainly will change frequently The aspects explained below are especially subject to change

Chart of accounts and other accounting codes The utility can expect frequent changes to the chart of accounts Most utilities subdivide the basic accounts to obtain a finer definition of business

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functions These "subaccounts" often change Less frequently, regulatory agencies make changes to the accounts Other company-defined accounting codes will change frequently as well Cost classification (expense type) codes, project codes, location codes, function codes, and activity codes can be expected to change continually throughout the life of the system

Organization Responsibility cost reporting requires that responsibility centers (the managers having responsible for expending corporate assets for business operations) be identified and that all costs the organization incurs be "tagged" to one of these centers To do this, a hierarchical model of the organization is encoded in computer tables Each time the organization changes, the coded model changes These changes can be expected frequently

Report and screen formats and content Report and screen formats and content will change as management's information needs change New information is needed as new business conditions develop Solving specific problems will require ad hoc reporting or inquiry

Processing Though changes to computer processing logic generally occur less frequently than changes to accounting codes, organization codes, or report formats these changes can affect a system more seriously than the other changes discussed Therefore, the system design should provide for computer processing logic changes

System modifications can be made relatively easily if the need is recognized during system design and if ease of modification is "built in" to the design Software packages now available for the common business applications described in this section are modular and integrated, and use tables and parameters that permit the types of changes described above They also have report writers and inquiry tools for flexible, efficient data access Accountants or clerical personnel can often make the changes, without assistance from programmers

[5] Personal Computers

The introduction of personal computers (PCs) has significantly reduced the cost and complexity of obtaining information Some utilities are developing distributed processing systems in which part of the computer processing is performed on PCs and the rest is performed on a microcomputer or mainframe Budget preparation is

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a good example of distributed processing, albeit on a rudimentary basis Historical cost data can be downloaded to an electronic spreadsheet from the financial systems on the mainframe Managers can then develop and revise their individual budgets on the PC When the budget is completed, it can be uploaded back to the mainframe for final approval and allocations

PCs are used extensively to analyze and prepare reports using data downloaded from the mainframe financial systems If a proper internal control system is not developed and maintained on PC local area networks (LANs) as well as on mainframe-based financial systems, the use of PCs to prepare and report of financial activities can result in a loss of control over accounting Security is frequently lax on LANS, one user is allowed access to another user's data

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Competition

- structure
- issues

CHAPTER 20

COMPETITION IN THE PUBLIC UTILITY INDUSTRY

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§ 20.01 Introduction

This book deals extensively with the historical development of public utilities as natural monopolies and the regulation of their operations and rates as a substitute for competition While many elements of these historical practices remain, in recent years the public utilities industry has faced increasing competitive pressure Certain segments of the industry have been more affected than others and some have already been largely deregulated

Many related factors can influence the speed and means of competitive change Some obvious factors are

(1) legislative, judicial, and regulatory changes that remove legal and other impediments to competition,

(2) the business environment in the United States or particular regions of the country, including the perceived availability of energy, and

(3) new and changing technology in the utility industry

Changes in utility operations and regulation have been influenced by each of these factors in recent years This chapter reviews some of the significant competitive developments in the public utilities industry, their impact on the operations and regulation of various segments of the industry, and the resulting effects on public utility accounting and financial reporting

§ 20.02 Competition in the Electric Industry

[1] Background

[a] Industry Overview

The electric utility industry developed as a vertically integrated industry Each utility, generally, owned its own generation, transmission, and distribution facilities Under their obligation to serve customers, electric utilities have undertaken to provide additional generating capacity in anticipation of increased customer demands To respond to these demands, electric utilities have the options of building additional generating plants, purchasing additional power on a long- or short-term basis, and employing demand-side management techniques (e g , offering customers financial incentives to make energy saving improvements to their homes or buildings) to reduce growth in demand

Through the 1950s and early 1960s, the utility industry focused on adding large oil, gas, and coal fired base-load generating plants These large plants, due to economies of scale, originally produced energy at lower costs than older plants However, the economies of scale began to disappear in the late 1960s The 1970s and 1980s saw the advent of nuclear-powered generation By the early 1990s, nuclear plants provided some 20 percent of the United States' total electric generating capacity Though additional nuclear power plant regulations and, for fossil-fueled plants, environmental regulations have made generating electricity more expensive, the overall cost of electric generation has declined because low priced natural gas has been increasingly used as a fuel and because of technological developments in the design of new power plants The newer designs save money through

- shorter construction periods,
- increased fuel efficiency, and
- reduced environmental costs

The most significant technological improvement is the combined cycle combustion turbine Plants using the cycle combustion turbine are generally are fueled by natural gas They are approximately 20 percent more fuel efficient than plants of earlier design Although the electric utility industry has preferred to use a diversified fuel mix to

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generate electricity, cycle combustion turbine plants will remain attractive if gas supplies are stable and remain reasonably priced. The availability of electricity at lower costs as a result of new technology is a driving force in the move toward competition in electricity markets Independent power producers, using the new technology, support deregulation because they see an opportunity to underprice existing utilities Industrial consumers support competition because they anticipate benefits from lower prices

[b] Legislative and Regulatory Developments

As a result of the 1973 oil embargo, which brought about oil shortages and higher oil prices in the United States, Congress passed the National Energy Act of 1978 (1978 Act) The goal of the 1978 Act was to reduce dependence on foreign oil and increase energy conservation One of the laws contained within the 1978 Act was the Public Utility Regulatory Policies Act of 1978 (PURPA) which encouraged the development of certain qualifying facilities These facilities consisted of cogenerators and small power production units that are exempt from federal and state regulations A typical cogenerator produces electric power and steam for use in a manufacturing facility The law required that electric utilities purchase the power from the qualifying facilities

The result of the development of qualifying facilities was that certain large utility customers had a competitive alternative source for at least a portion of their energy needs and that electric utilities had to consider this new competition when making decisions about constructing new power generating facilities

Competition in electric generation has been of ongoing interest at the Federal Energy Energy Regulatory Commission (FERC) Many of the FERC's policies have been developed in individual rate cases, and have focused on utilities' and independent power producers' use of market-based rates in wholesale power transactions The FERC policy required that the seller not have market control over both generation and transmission activities or that the seller abate that power if it did exist If a seller made its transmission facilities accessible, the FERC normally would be satisfied that market power over transmission facilities did not exist The FERC has stated that open access can be accomplished by filing an open-access transmission tariff that provides access to third parties on a basis comparable to

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the transmission provider's own use of the system The FERC also bars preferential transactions, especially transactions with a utility's affiliates, without proper justification

In 1994, the FERC announced that for new, unbuilt generating capacity, it will no longer focus on whether the seller has market power in generation when considering requests for market-based rates Instead, the FERC will focus on whether the seller or its affiliates have market power over transmission in the particular market, whether such power has been adequately mitigated, and whether the utility or its affiliates possesses other barriers to the entry of competition The change in policy occurred because the FERC believes that if transmission market power is mitigated and the seller cannot erect other barriers to entry, the threat of other suppliers' entry into wholesale generation markets will be enough to prevent the seller from exacting monopoly prices

In 1995, the FERC published a notice of proposed rulemaking (NOPR) addressing (1) open transmission access, and (2) recovery of stranded costs These issues are critically important to the electric utility industry's transition to fully competitive markets

The open transmission access part of the proposed rule, would require all utilities under the FERC's jurisdiction to file non-discriminatory, open access transmission tariffs, available to all wholesale sellers and buyers of electric energy The utilities would also be required to take service under the same tariffs for their own wholesale sales and purchases of electric energy The stated goals of the open transmission access proposal are (1) to facilitate the development of a competitive generation market by ensuring that wholesale buyers and sellers can reach each other, and (2) to eliminate anti-competitive and discriminatory practices in transmission services

In addressing stranded costs, the 1995 NOPR was a follow-up to the 1994 proposal on the same subject The 1994 NOPR was the subject of much debate and many comments and this feedback led to the supplemental NOPR contained in the 1995 NOPR readdressing the issue

In the supplemental NOPR, the FERC stated its belief that, "the approach proposed in the Stranded Cost NOPR should adequately cover most, if not all, costs that could be stranded in an environment where transmission access is more widely available, including the

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access environment that the FERC expects if the provisions of the Open Access NOPR are adopted"

The open access and stranded costs provisions of the 1995 NOPR are quite extensive and may be changed substantially as the review and debate process transpires However, the major features of FERC's position advocating expanded transmission access and provisions for recovery of the resulting stranded costs are expected to become standard regulatory practice

While the FERC has taken the lead in promoting competition at the wholesale level in the electric utility industry, state commissions have focused on using integrated resource planning In process, state commissions establish rules that may require competitive bidding for new power plant construction and power purchase arrangements, and incentives for conservation For example, to reduce the need for future electric generating capacity, most state regulators have developed demand-side management (DSM) programs to promote efficiency and the ability to manage loads

[2] Energy Policy Act of 1992

The Energy Policy Act of 1992 (1992 Act) contains provisions to further foster competition in the electric segment Important aspects of the 1992 Act are described below

[a] Changes in PUHCA

A new category of power producers known as "exempt wholesale generators" (EWGs) was created under the 1992 Act EWGs are permitted to

(1) generate power and sell it at wholesale without becoming subject to the restrictive provisions of the Public Utility Holding Company Act of 1935 (PUHCA),

(2) invest in independent power production (IPP) facilities outside the United States, even if the foreign company sells power at retail, provided that none of the generated electric energy is sold to consumers in the United States, and

(3) enter into affiliate transactions with a related utility if approval is obtained from the appropriate state regulatory commission

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An EWG is defined as an entity determined by the FERC to be engaged, either directly or indirectly, in the business of owning and/or operating an eligible facility (i e , a facility generally used for the generation of electric energy exclusively for sale at wholesale) and selling electricity at wholesale Regulated utilities are allowed to spinoff existing generating facilities from their rate base to an EWG, if each state commission with jurisdiction over the utility's retail rates finds that the change would benefit consumers, serve the public interest, and not violate state law The FERC is required to act within 60 days of a request for EWG status During the FERC's ruling period, a good-faith exemption is provided that allows registered holding companies to begin project formation in the same manner as exempt utilities and non-utility companies

The Energy Policy Act of 1992 allows holding companies registered under the Public Utility Holding Company Act of 1935 (PUHCA) to invest in exempt wholesale generators (EWGs), no matter where they are located and in utilities located outside of the United States

In October 1993, the SEC published final rules that permit registered holding companies to invest in EWGs without SEC approval [1] No SEC approval is required as long as the holding company's aggregate investment in EWGs and foreign utility companies (FUCOs) is not greater than 50 percent of its consolidated retained earnings If the company incurs a 10 percent reduction in average consolidated retained earnings over four consecutive quarters (compared to the same four quarters in the preceding period), the retained earnings test is not used Instead, additional investments in EWGs and FUCOs are limited to 2 percent of total capitalization The SEC has deferred action on additional rules regarding FUCOs

Over the years, the SEC has continued to refine its application of PUHCA The general trend beginning in the late 1980s, and accelerating with the passage of the Energy Policy Act of 1992, has been to loosen the restrictions imposed under PUHCA In 1994, the SEC inaugurated a comprehensive study of regulation under the Public Utility Holding Company Act with two days of round table discussions held in Washington DC At the round table, representatives from a

[1] Release No 25866 File No S 7-9-93 Under PUHCA before this order when a registered holding company issued or guaranteed securities to finance these acquisitions it had to have SEC approval and the SEC had to the interests of the electricity customers

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variety of interested parties including public utilities, state and federal regulators, consumer groups, rating agencies, and others met to discuss issues surrounding PUHCA regulation While there was wide diversity in the parties' views of what future regulation should look like, there was general agreement that reform was needed given the changes which have taken place in the utility industry since the inception of PUHCA in 1935

In November of 1994, the SEC issued a request for comments on the modernization of PUHCA, ushering in the next phase of its study of PUHCA regulation Citing increasing competition in the utility industry, changes in state and federal utility regulation, and changes in federal securities laws and securities markets, the SEC said, "developments in recent years require reexamination of the need for, and role of, a federal holding company statute "

The SEC's study of PUHCA culminated in June of 1995 when it released its findings in a report titled, "The Regulation of Public Utility Holding Companies " The report focused on both legislative and administrative options for the reform of public utility holding company regulation

The report presented three possible recommendations for legislative reform of PUHCA The first, and the option favored by the SEC, involves conditional repeal of PUHCA This option would provide for repeal of PUHCA with much of the SEC's current audit authority and affiliate transaction oversight responsibility being shifted to the Federal Energy Regulatory Commission (FERC) In addition, legislation would be passed to allow the states access to holding company books and records, as necessary, to enable them to carry out their regulatory responsibilities The second option would be unconditional repeal of PUHCA without providing any of the safeguards mentioned above The third option would be to leave PUHCA in force but enact an amendment granting the SEC broader exemptive authority under the Act It will be up to Congress to decide which of the options, if any, to pursue

The report also outlined a number of recommended administrative actions which the SEC should implement pending action by Congress Among the reports recommendations were suggest to the SEC to

- consider rules to broaden exemptions for routine financing,
- liberalize the treatment of financing not exempted under Rule 52 (the rule that exempts issuances of securities by public

utility companies from the requirements of Sections 6 and 7 of PUHCA, if the proceeds are to be used to finance their utility business and the issuance is expressly approved by the state commission in the state where the utility is organized and doing business),

- avoid unnecessary restraints on utility acquisitions,
- consider a rule to reduce the burdens on energy-related diversification,
- continue to administer PUHCA flexibly, in consultation with other regulators, with respect to matters that do not fall under the proposed diversification rule
- withdraw its proposal to amend rule 90 (the proposal to require that affiliate transactions within a holding company system be priced at the lower-of-cost-or-market) concerning affiliate service, sales and construction contracts,
- apply more liberal interpretations of the standards for exemption, when the affected states agree, and
- direct more resources to the audit function

During the next year or two, regulation of public utility holding companies under PUHCA will, almost certainly, go through significant changes The trend toward decreasing regulation in this area will probably continue, consistent with the trend toward decreasing regulation throughout the industry in general

[b] Transmission Access

The transmission provisions of the 1992 Act are designed to increase competition in the wholesale power market and encourage more efficient production of electric energy The FERC has been given authority to order utilities to provide point-to-point access on transmission systems at rates that would recover all legitimate, verifiable, and economic costs, including an appropriate share of the costs of enlargement of the facilities The FERC may order a utility to provide access to an electric utility, federal power marketing agency, or any other entity that generates electricity for sale or resale

A utility may be excused from providing access to an outside entity if, after making a good faith effort, it is unable to obtain the necessary approvals or property rights for the expansion of capacity This

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situation may arise when the ordered transmis n services require enlar ment of transmission capacity The FE , is restricted from issuing transmission orders that would impair the reliability of electric systems and is prohibited from issuing orders requiring retail wheeling or sham transactions

In 1995, the FERC issued a Notice of Proposed Rulemaking (NOPR) addressing the filing by all utilities under its jurisdiction of open transmission access tariffs for use by all wholesale sellers and buyers of electric energy (see § 20 02[2][a]) The FERC's support for its authority to order utilities to provide open and comparable transmission access is that the absence of open access results in undue discrimination in wholesale power markets, which the FERC is, by law, required and authorized to remedy The FERC expressed the belief that any transmission arrangements short of full, open, and comparable access are inconsistent with its obligations to ensure that wholesale power transactions are free from undue discrimination The NOPR is expected to create a substantial amount of response and a variety of challenges The final results may not be determined for some time

[3] Retail Wheeling

A ough the 1992 Act does not permit the FERC to order retail whe , the Act does not prevent states from doing so During 1994, man tes began to consider, and at least two states began to explore in detail, the concept of retail wheeling

In Michigan, the Public Service Commission initiated a plan for a five-year, limited experiment with retail wheeling of 60 megawatts of retail capacity for the Consumers Power Company and 90 megawatts for Detroit Edison Certain customers that use between two and ten megawatts of retail capacity per location will participate in the experiment The program will be coordinated with needs for additional supply and solicitations for additional capacity This coordination is aimed at minimizing the possibility of the experiment resulting in stranded investments

The California Public Utilities Commission (CPUC), in 1994, announced a proposal to restructure the state's electric utility industry and ntually unbundle ex g utilities' services The original prop would have permitt stomers to elect to become direct access customers in stages, w the largest customers being eligible

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in 1996 and all customers being eligible by 2002 The proposal would have changed the basis for utility regulation from costs to provide service to performance

The original proposal has since given way to two competing proposals The first, and currently favored, proposal provides for the establishment of a centralized power pool (POOLCO) which would serve to establish a market clearing price and would operate as a large spot market in which all generators would be required to participate All power would be bought and sold through the POOLCO and all consumers would have access to POOLCO's market-priced power The second proposal focuses on contractual arrangements directly between electric generators and the consumers to establish the market price for power Both of these competing proposals provide for recovery of utilities' legitimate and verifiable stranded costs, both would ensure the integrity of the power grid through a centralized system operator, and both would provide for all participants in the market to have equal access to transmission facilities

The California restructuring is ongoing, the state legislature is currently considering several different restructuring bills It is unclear when either the CPUC or the state legislature will take final action on electric industry restructuring

§ 20 03 Competition in the Telecommunications Industry

[1] Background

A milestone in the deregulation of the telecommunications market was reached in 1982, when the American Telephone & Telegraph Company (AT&T) was ordered to divest itself of its monopoly providers of local services, the Bell Operating Companies Under the terms of the order, AT&T retained its long lines division, the long distance facilities of the local companies, and its equipment manufacturing subsidiary, Western Electric The local exchange access facilities, retained by the Bell Operating Companies, were viewed as a natural monopoly, and the Bell Operating Companies were barred from entering the long distance and equipment manufacturing markets It was argued that if the Bell Operating Companies were allowed to compete in long distance markets, they would subsidize local service through artificially high long distance rates This practice, which prevailed in the vertically integrated days of the Bell Telephone

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System, was the product of a lack of competition as well as of decades of federal and state regulatory policy promoting the subsidy of local service The Be. Operating Companies were barred from equipment manufacturing because of concerns that they would be able to sell equipment to themselves at inflated prices and pass those costs on to their monopoly customers

[2] Recent Developments

With the telecommunications mar' ' becoming more competitive since the break up of AT&T, limits ompetition, as ·ll as other assumptions about competition in th iecommunicat industry, have become a source of controv y In 1994, le ation was introduced to address the Bell Operating Companies' entry into the long distance and equipment manufacturing markets It was argued that these markets are workably competitive, and the concerns of a decade ago have largely been alleviated

Four of the Bell Operating Companies have, meanwhile, joined together to file a formal request asking to rescind certain provisions of the original AT&T break-up order The companies contend that the provisions barring them from entry into the long distance and equipment manufacturing markets have outlived their usefulness and simply act as artificial barriers to entry Increasing competition in local exchange services from interexchange carriers (IXCs), cellular companies, competitive access providers, and others has called into question the premise that local exchange access markets are natural monopolies The Bell Operating Companies argue that they should be able to compete in the interLATA long distance marketplace when other companies can freely compete with the Bell Operating Companies in the local exchange marketplace

The Bell Operating Companies face significant opposition in their quest to enter the long distance and equipment manufacturing markets The opposition argues that the factors that led to preclusion of the Bell Operating Companies from these markets in 1982 (i e , subsidizing one class of customers through rates charged to another class of customers and the threat infair pricing on anuf ured goods) have not been alleviated ar ontinue to threaten fair co petition The issue of the Bell Operating ompanies' entry into the long distance and equipment manufacturing markets will likely continue to be hotly debated in the courts and in Congress

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[3] Regulation of Telecommunications

By 1984, AT&T had divested itself of the Bell Operating Companies and was operating in an environment in which competition was increasing As a result of changing market conditions and emerging competition, alternative methods of regulation began to emerge These alternative methods, it was argued, furthered competition and would lead to more efficient markets The trend for regulators to apply new types of regulation began with the 1989 FCC approval of an AT&T price cap program This program contained price ceilings which limited percentages by which rates could be increased in a given period of time In addition to the rate ceilings contained in the original proposal, the FCC included price floors (limits on percentages by which rates could be decreased in a period of time) in its adoption of the price cap program, effectively creating price bands as the new form of regulation This new form of regulation was viewed as a way for the FCC to encourage competition The move away from cost-of-service regulation has continued since 1989 and price caps, as well as other types of incentive regulation, have found their way into other telecommunications services, such as local exchange service

Regulation of telecommunications companies continues to be the responsibility of two groups whose interests often diverge, the FCC and state regulators State regulators control rates for local exchange service and intrastate long distance services They often balance the objectives of preserving traditional subsidies of local exchange service rates and preserving universal telephone service for the public with the competing objective of promoting competition in the market for long distance services As a broader range of telecommunications services become competitive, the FCC's policies have focused on introducing competition in an appropriate manner while encouraging incentive regulation and marketplace determination of rates

The mix of regulatory schemes among the FCC and state regulators is diverse Some states regulate local exchange companies using traditional cost-of-service ratemaking methods Other states favor incentive regulation techniques The FCC has established a form of incentive regulation through its price cap regulations for the interstate services of local exchange companies, primarily exchange access services provided to long distance companies

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§ 20.04 Competition in the Cable Television Industry

[1] Background

The Cable Communications Policy Act of 1984 (1984 Act), which largely deregulated rates for the cable television industry, was passed in response to arguments that effective competition existed in the cable industry and, therefore, rate regulation was not needed Congress had expected rates to decrease after deregulation, instead, in the years following the initial deregulation of cable rates paid by customers increased substantially This result raised questions about whether the majority of cable companies, in fact, faced effective competition

Congressional concern that cable operators had undue market power continued to gr As a result of this concern, and because of Congress' disapp ment that rate decreases envisioned with the 1984 deregulation of the cable industry never materialized, Congress voted to reregulate cable On October 5, 1992, the Cable Television Consumer Protection and Compe Act of 1992[2] (Cable Act of 1992) bec law

[2] able Television Rate ulation

The Cable Act of 1992 amended Section 623 of the Communication Act of 1934 and subjects cable systems that are not subject to effective ompetition to regulation of rates for cable service other than per nannel and pay-per-view services The Cable Act of 1992 generally empowers local franchising authorities to regulate basic service, and the Federal Communications Commission (FCC) to regulate programming services Regulation of cable system rates by local franchising authorities is subject to review by the FCC

In May 1993, the FCC released a Report and Order and Further Notice of Proposed Rulemaking,[3] establishing rules to implement cable rate regulations The rules provide for a benchmark and price-cap approach, whereby existing rates for cable service are compared to a benchmark that reflects the rates charged by cable systems that are considered to be subject to effective competition Systems with current rates above the benchmark are generally required to reduce their rates to the lesser of the benchmark or to the system's rates in effect at

[2] 102-385 §§ 3, 9, 14 106 Stat 1460 (1992)

[3] MM Dkt No 92-266

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September 30, 1992 minus 10 percent In February 1994, the FCC adopted regulations that revised the benchmark formula, effective May 15, 1994 The new formula requires that regulated cable operators reduce rates by up to 17 percent from the September 30, 1992 levels A price cap mechanism governs subsequent changes in rates This mechanism permits an annual adjustment to rates, to reflect the effects of inflation and other increases in external costs As an alternative to setting rates based on the benchmark and price cap method, the FCC will permit cable operators to justify rates above benchmark or capped levels using a cost-of-service approach

In February 1994, the FCC adopted a Report and Order[4] that establishes requirements for regulators setting rates under the cost-of-service alternative The rules were adopted on an interim basis, pending completion of cost studies of the cable industry Along with the Report and Order, the FCC issued a Further Notice of Proposed Rulemaking, that requests comments on methods used to ascertain a cable system's rate of return and on proposed rules for a uniform system of accounts

The regulatory framework for cost-of-service filings developed and proposed by the FCC relies heavily on traditional regulatory approaches adopted for other regulated public utilities The new regulators of the cable television industry appear to view an appropriate cost-of-service filing for cable television services as consistent with many of the regulatory standards traditionally applied to telephone companies, although the new regulations have attempted to simplify the regulatory process

§ 20.05 Competition in the Natural Gas Industry

The natural gas segment of the public utility industry is made up of three levels of operations

(1) gas production,

(2) pipeline transmission, and

(3) local distribution

While the natural monopoly on local distribution has remained relatively intact, production and transmission of natural gas started to become more competitive with the Natural Gas Policy Act of 1978

[4] MM Dkt No 93-215, CS Dkt No 94-28

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This trend has continued through the implementation of FERC Order No 636

[1] Industry Overview

Through the 1970s, local distribution companies purchased natural gas from interstate gas pipeline companies that provided a full range of services gas acquisition, gathering, transmission, and storage Local distribution companies purchased the gas from interstate pipeline companies at prices (which included commodity and demand charges) based on cost of service as regulated by the FERC The pipeline companies purchased gas from producers, at prices also regulated by the FERC In the mid-1970s, the demand for natural gas grew The regulated prices that producers could charge for natural gas to be sold on the interstate market, however, were insufficient to encourage increased exploration Producers dedicated newly discovered gas to the intrastate markets, where the selling prices were unregulated and, therefore, higher Because of the lower, regulated prices in the interstate market, less gas was made available for interstate sale As a result, many local distribution companies resorted to investing in gas exploration and development activities to ensure their customers an adequate supply of natural gas

[2] Legislative and Regulatory Developments

The Natural Gas Policy Act of 1978 (NGPA) caused a number of changes in the industry The NGPA deregulated the prices that producers could charge for natural gas from certain, newly developed sources, and set in place the framework for complete deregulation of producer prices The purpose of the NGPA was to provide incentives to drill for natural gas by allowing the price that producers could receive for their gas to be determined by competition rather than by governmentally established limits

The NGPA was accompanied by a number of related changes instituted by the FERC, in the words of a FERC chairman, "to eliminate regulatory impediments to competition and to allow demand for gas and gas delivery services to establish the price for gas and those services " These orders directly affected the production and interstate transmission of natural gas They also have had an impact on local distribution companies

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[a] FERC Order No. 380

In May 1984, the FERC issued Order No 380,[5] which required that variable costs be eliminated from pipeline minimum commodity bills The FERC concluded that including the recovery of variable (primarily purchased gas) costs in the minimum commodity bills insulated pipelines and producers from market risk, inhibited the effect of market forces in determining gas prices, and operated as a restraint on competition

One of the FERC's principal objectives in issuing Order No 380 was to encourage the development of a price-responsive market for natural gas The order also had the effect of focusing the industry's attention on the existence of economically unsound and inefficient high-take and high-price contracts between pipelines and producers

[b] FERC Order No. 436

In October 1985, the FERC issued Order No 436,[6] adopting regulations designed to encourage pipelines to voluntarily open their systems to nondiscriminatory transportation of natural gas so that local distribution companies and end users could purchase gas directly from diverse sources under competitive market conditions In addition to encouraging open access and nondiscriminatory transportation, Order No 436 resulted in significant restructuring of pipeline rates with the goal of increasing pipeline throughput (i e, total volume of gas transported through the line) Most major pipelines filed as Order No 436 transporters

In Order No 436, the FERC rejected pipeline requests that, to obtain nondiscriminatory transportation, producers be required to waive rights under the take-or-pay provisions of their existing contracts The FERC instead provided for expedited review of take-or-pay buy outs and producer abandonment applications resulting from renegotiated take-or-pay contracts

Order No 436 established a voluntary framework that the FERC believed would provide benefits of competition to all consumers The rule provides for·

(1) optional self-implementing transportation,

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[5] Dkt No RM 83-71-000 (May 25 1984)

[6] Dkt No RM 85-1-000 Parts A-D (Oct 9 1985)

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(2) optional expedited certificates for entry into new markets, and

(3) a reaffirmation of the FERC's policy on buy outs of take-or-pay obligations

In June 1987, a federal appeals court panel upheld most elements of the FERC's Order No 436, but remanded three key issues to the FERC for further proceedings [7] The court generally upheld the substance of the order, the FERC's authority to impose such a rule, and the FERC's procedures employed in adopting it The court ordered the FERC to change or justify

(1) contract demand adjustments,[8]

(2) recovery of take-or-pay obligations, and

(3) grandfathering provisions

See § 20 05[2][d], below, for a discussion of the FERC's response

[c] FERC Order No. 451

In June 1986, the FERC issued Order No 451 [9] This order is similar to Order No 436 in that it attempted to inject more competition into the natural gas market, in this case, into wellhead gas pricing Order No 451 revised the price structure of old gas to reflect more accurately the commodity value of the gas in a competitive market The order required producers seeking to renegotiate prices for old gas to agree to renegotiate prices for all new gas sold under contracts containing any old gas The FERC found that this price renegotiation process would have the effect of further exposing all new gas to market forces The purpose of this order is to eliminate market inefficiencies and

[7] Assoc Gas Distribs et al v Fed Reg Commn Dkt No 85-1811

[8] To make customers access to the wellhead market meaningful Order No 436 provides customers a limited right to unilaterally modify their contracts with pipelines that elect to operate under the order It entitles a party with a firm sales contract on the date the pipeline becomes subject to Order No 436 to (1) convert specified percentages of its contract demand from gas purchase to unbundled gas transportation or (2) reduce its contract demand by the same percentages The entitlement to convert or reduce is 15 percent for each of the first and second years, 20 percent for the third year and 25 percent for each of the fourth and fifth years The entitlements are cumulative While the court accepted the FERC's conclusion on contract demand conversions it agreed with the petitioners that the FERC had failed to adopt an adequate rationale in support of contract demand reductions

[9] Dkt No RM 86-3-000 (June 6, 1986)

distortions that hinder the development of adequate long-term supplies It seeks to protect the parties' rights under existing contractual arrangements and, at the same time, to provide an opportunity for gas to reach new purchasers at market prices

To achieve these objectives, Order No 451 mandates the following

(1) Elimination of the vintaging system for pricing of old gas that is subject to the FERC's regulations and establishment of a single ceiling price (subject to inflation adjustments) for the old gas

(2) Institution of good faith negotiation procedures whereby producers may request purchasers with escalating price contracts to nominate a new price up to the new ceiling price The purchaser then has four options available

(a) Take no action within 60 days The producer is automatically granted an abandonment, may seek out other purchasers, and has the right to cancel the existing contract on 30 days' notice

(b) Offer to purchase at the new ceiling price The producer must continue the contract at the new price

(c) Offer less than the new ceiling price The producer has the option of accepting or rejecting the offer In the event of rejection, the producer is automatically granted an abandonment and may seek new purchasers but must continue sales under the existing contract until a new purchaser is located

(d) Offer to subject all old gas and old/new gas combination contracts to renegotiation If the producer rejects this offer, the purchaser has the right to cancel these contracts at any time and the producer is automatically granted an abandonment

The FERC also required that the sale of old gas under the abandonment rules of Order No 451 be subject to a right of first refusal by firm customers of a non-open-access transporter That is, these customers have the right to contract for abandoned gas at the rate agreed to by the producer and the proposed new third party purchaser

In September 1989, the Fifth United States Circuit Court of Appeals vacated FERC Order Nos 451 and 451-A in *Mobil Oil Exploration*

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and Producing Southeast v FERC [10] The Court maintained that Order No 451 had essentially achieved *de facto* deregulation of old gas, which was inconsistent with Congressional intent as expressed in the Natural Gas Policy Act (NGPA) In January 1991, the Supreme Court overturned the Court of Appeals decision and upheld FERC Order No 451 in its entirety The Court determined that Congress gave the FERC the authority to revise the pricing of natural gas from wells that were in production before November 1978 With the enactment of the Natural Gas Wellhead Decontrol Act of 1989, all remaining wellhead price controls were removed effective as of January 1993

[d] FERC Order No 490

Abandonment is the authority granted by the FERC to abandon facilities or services rendered for which certificates had been granted Abandonment allows pipelines to, instead, sell to new buyers, or old buyers, at newly negotiated rates In February 1988, the FERC issued Order No 490, which amended FERC regulations to provide for abandonment of certain sales and purchases under the Natural Gas Act by sellers and purchasers in the following cases

(1) the underlying contract term has expired,

(2) the contract has been terminated under a provision of the contract, or

(3) the sales and purchase obligations have been eliminated or modified by mutual agreement of the parties

When a contract for the sale of natural gas has expired or has been terminated, either party to the contract may, upon 30 days written notice, abandon its obligation to sell or purchase the gas If the parties agree to terminate the contract or to modify their sales and purchase obligations under the contract, the abandonment is effective in accordance with the parties' agreement

If an interstate pipeline purchaser abandons purchases from a producer, it must continue to transport the "abandoned" gas if the producer so elects

[e] FERC Order No. 500

A take-or-pay clause requires a pipeline to commit itself to take a specific amount of gas and to pay the producer for it, regardless

[10] 885 F2d 209

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of whether the gas is actually taken Take-or-pay clauses are generally intended to shift to the pipeline the risk that periodic engineering or operating problems may prevent it from physically taking the gas Unless the contract also contains a market out type of clause, the pipeline also faces the risk that its customers will not buy the gas it has contracted to purchase This situation occurred during the 1980s Customers bought less gas from pipelines, They bought it instead, directly from producers and moved it through the pipelines under transportation arrangements As a result, the pipelines incurred take-or-pay liabilities The FERC viewed the growth of take-or-pay liabilities as an impediment to the establishment of market responsive prices and the unbundling of natural gas service that it had encouraged through Order Nos 380, 436, and 451

In August 1987, the FERC issued an "interim" transportation rule, Order No 500[11] to cure the "deficiencies" found by the court in Order No 436 Order No 500 reaffirms the FERC's open-access transportation program established in Order No 436 With the following four modifications,

(1) A pipeline may work off a portion of its take-or-pay liabilities by transporting gas for its producers For contracts signed before June 23, 1987, producers must offer to credit gas transported by a pipeline against that pipeline's take-or-pay liability [12] In addition, to compute the pipeline's take-or-pay liability, volumes of gas transported under open access must be treated as though they are volumes purchased by the pipeline under contracts signed before June 23, 1987 The intent of the crediting provision is to stop "cherry-picking" among the contracts (i e , to prevent producers from offering low-cost gas for transportation while holding onto high-cost gas, thereby maximizing take-or-pay accruals)

(2) Costs to buy out or buy down past take-or-pay liabilities may be allocated between the pipelines and their distribution company customers The FERC adopted two pass-through mechanisms One mechanism allows all pipelines

[11] Dkt No RM 87-34 (August 7 1987)

[12] A pipeline is allowed to refuse transportation services for producer-owned gas unless the producer offers the pipeline Mcf-for-Mcf crediting against its existing take-or-pay liabilities

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to pass through to customers commodity rates of all prudently incurred take-or-pay buy out or buy down cost obligations An alternative recovery mechanism, available only to pipelines transporting on an open access basis, permits costs to buy out or buy down take-or-pay liabilities to be recovered through the following methods

(a) Between 25 percent and 50 percent of the buy out or buy down costs can be recovered through a fixed charge to customers provided that the pipeline absorbs an equal percentage of these costs

(b) Remaining buy out or buy down costs may be recovered through a commodity surcharge on total throughput

(3) The contract demand reduction provision in Order No 436 (that allowed customers to reduce firm purchase commitments) is eliminated, but retained is the contract conversion provision (that allowed customers to convert sale. service to transportation service) The grandfathering provisions of Order No 436 are reaffirmed

(4) To prevent future take-or-pay problems, principles are established to enable pipelines to design rates to recover the costs of maintaining gas supplies for their customers The principles permit a pipeline to use an inventory charge to bill distribution customers for future take-or-pay expenses, to the extent that they agree to buy gas from the pipeline A pipeline already transporting gas on an open-access basis may absorb between 25 percent and 50 percent of its take-or-pay buy out or buy down costs and recover an equal percentage from its customers through a fixed take-or-pay charge Additional amounts of up to 50 percent of the pipeline's total buy out or buy down costs may be recovered through a commodity charge, a volume-based charge, or some mix of both

For this last type of rate design

(a) Only Order No 436 transporters may include in their rates a charge for standing ready to supply gas to customers

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(b) The pipeline may not recover take-or-pay or similar charges by any other means

(c) Sales customers must be permitted to renegotiate their sales levels of service at regular intervals

(d) A customer who nominates a new level of service automatically consents to abandonment of the difference between the existing level of service and the new lower level

In October 1987, the FERC partially revised the crediting mechanism in Order No 500-B Under the revision, a binding offer of credit against take-or-pay liabilities would be sufficient to require the pipeline to transport all volumes if the offer is signed by the producers and owners of 85 percent of the volumes to be transported

In December 1987, the FERC issued Order No 500-C, clarifying changes in the crediting mechanism The order addressed concerns about the effects of credits on casinghead gas, new gas, intrastate pipelines, and processing plants

In March 1988, the FERC issued Order No 500-D, extending the Order No 500 interim rule determination date of April 1, 1988, for an indefinite period

In December 1988, the FERC issued Order No 500-F, extending to March 31, 1989, the deadline for filing tariff sheets to recover take-or-pay buy out and buy down costs under the Order No 500 alternative pass-through mechanism It also granted pipelines an exception to the deadline of March 31, 1989, for contracts in litigation on that date

In October 1989, the United States Circuit Court of Appeals for the District of Columbia responded to *American Gas Association v FERC*[13] by ordering the FERC to either issue a final order or abandon the interim one The Court rejected the sunset provision of Interim Order No 500 (extended by Order No 500-F) and also objected broadly to it, requiring the FERC to either explain or abandon altogether Order No 500 and related orders The Court primarily directed the FERC to provide additional reasoned support for the take-or-pay provisions of the order

In December 1989, the FERC issued Order No 500-H, the final open-access rule, which essentially adopted interim Order No 500

[13] No 87-1588 et al (DC Cir 1989)

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with modifications to respond to the Court's objections Order No 500-H established a permanent, open access, nondiscriminatory gas transportation program and addressed the Court's concerns about the resolution of the take-or-pay aspects of Order No 500 Among the more significant changes to the interim rule, the final rule (1) extended the sunset date for the alternative pass-through mechanism to December 31, 1990, and (2) explained that the FERC has neither jurisdiction nor interest in influencing state regulators in their ultimate disposition of the take-or-pay costs passed through to local distribution companies Although the FERC believes that take-or-pay costs should be shared equitably, it affirmed that absorption of any of these costs by the local companies is a state regulatory issue

The FERC denied all requests for rehearing on Order No 500-H except one In Order No 500-I, the FERC extended the period in which pipeline companies must give notice before applying take-or-pay credits to must-take gas The notice period was changed from 30 to 60 days

The FERC concluded that its reasoning about the much challenged take-or-pay crediting mechanism was correct The FERC also reaffirmed its purchase deficiency allocation mechanism for the pass-through of take-or-pay costs Finally, the FERC stood by its gas inventory charge policy

On February 13, 1991, the FERC issued Order No 500-J This order stays the operation of FERC Regulations Section 284 221(d) for firm transportation converted from firm sales after the date of the order on remand These converted transportation arrangements may be abandoned only on an individual basis under Section 7(b) of the Natural Gas Act Section 284 221(d) will continue to be in effect for all other transportation arrangements covered by those regulations

[f] FERC Order No. 497

In June 1988, the FERC adopted Order No 497[14] to regulate pipeline marketing affiliates Producers have long complained that gas pipelines favor their own affiliates in gas purchases and transportation

Order No 497 delineates practices prohibited by interstate pipelines and their marketing affiliates, under the Natural Gas Act and Natural Gas Policy Act It also includes proposed reporting requirements aimed

[14] Dkt No RM 87-5 (June 1 1988)

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at detecting discriminatory or other unlawful practices and proposed remedies for violations of substantive standards or reporting requirements Companies may incur civil penalties for committing knowing violations

In January 1990, after a rehearing on Order No 497, the FERC revised its guidelines on the types of entities and transactions covered by the final rule It also clarified the types of transactions with a marketing affiliate that subject a pipeline to the rule and what activities constitute "marketing" under the rule Two new standards of conduct were incorporated into the rehearing order to govern the relationship of pipelines and their marketing affiliates (1) if a pipeline offers a transportation discount to an affiliated marketer, it must make a comparable and contemporaneous discount available to all similarly situated nonaffiliated shippers, and (2) a pipeline must maintain its books and records separately from its affiliate

[g] FERC Order No. 636

The FERC's efforts to increase competition in the natural gas market took a large step forward on April 8, 1992, when FERC Order No 636 was issued Order No 636 represents the culmination of the process that began when the FERC first proposed a new natural gas market structure in a July 31, 1991, notice of proposed rule making commonly referred to as the "mega NOPR "

The objective of Order No 636, like Orders No 436 and No 500 before it, is to reinforce the right of nondiscriminatory access to interstate pipeline capacity by all interested buyers and sellers of natural gas The FERC believes that the rule, when fully implemented, will complete the structural changes that began with the passage of the Natural Gas Policy Act of 1978 (NGPA) Order No 636 was effective as of May 18, 1992 It is intended to further the FERC's goal of fostering competition by ensuring that interstate pipeline transportation services are equal in quality for all gas supplies whether the buyer purchases gas from the interstate pipeline or from any other gas supplier (e g , a producer or marketer) In theory, Order No 636 should give any gas buyer access to essentially all gas suppliers and should lead to an efficient, competitive natural gas market A number of key considerations are included in Order No 636 They are discussed in the following paragraphs

Under Order No 636, pipelines are required to completely unbur e their transportation services from sales This change will end traditional interstate pipeline merchant sales for a pipeline at purchased gas from producers, transported it through its own system, and resold it directly into the customer's system The FERC believed that the traditional merchant service would always be perceived as giving the pipelines an unfair competitive advantage over other gas sellers who lack a proprietary delivery system Under Or r No 636, pipelines are still allowed to sell gas, but only at an ups m point (i e , before the gas is transported), on th ame compe e basis as all other sellers The transportation of gas from the pstream point to the customer must then be purchased in a separate transaction

An existing firm sales customer of a pipeline is to be converted to an unbundled firm transportation customer upon the pipeline's acceptance of a blanket sales certificate at market-based rates and the expiration of the customer's existing contract The customer is then responsible for negotiating firm supply contracts with the pipeline or with another supplier

Pipelines are required to offer an unbundled 'no-notice' transportation service, in addition to their current fi transportation service, if they are currently offerin no-notice b ed firm sales service A no-notice transport service allows firm c mers to duplicate the characteristics of their former firm sales s ice, such as receipt of unnominated volumes to meet unexpected requirements, without incurring daily balancing and scheduling penalties

Gas storage f under the definition of transportation and is to be offered on a nondiscriminatory, contract basis With the FERC's unbundling of pipeline sales and transportation, pipelines will need storage beyond the unbundling point only to perform loan balancing and to provide "no-notice" transportation Thus, the remaining storage will be available to sell to transportation customers

The rate-setting method the FERC prefers for the new gas market is the straight fixed variable (SFV) method SFV generally results in a two-part rate The demand component is loaded with all of the pipeline's fixed costs (including the authorized rate of return) The commodity component is loaded with only the pipeline's variable operating costs The FERC's intent in choosing the SFV method was to ration pipeline capacity by making it cost prohibitive to

oversubscribe on firm capacity SFV is not mandated, however The FERC will consider other rate-setting methods on a case-by-case basis

Under "capacity releasing" the pipeline, serving as the middleman, will promote the competitive exchange of excess pipeline capacity Firm capacity holders are permitted to permanently or temporarily release some or all of their capacity to parties desiring that capacity The released capacity will be rewarded to the highest bidder Pipelines are required to develop and maintain user-friendly electronic bulletin boards to show available capacity The purpose of the bulletin boards is to ensure full and equal access to information on capacity availability at all points

There are additional considerations relevant to the actual implementation of Order No 636 In order to encourage the development of a competitive market, the FERC has stated that customers of downstream pipelines must have access to the production areas and gas sellers reached through the capacity of upstream pipelines Under Order No 636, firm transportation customers of downstream pipelines are allocated and assigned capacity of upstream pipelines previously held by the downstream pipelines Pipelines retain operational control of their systems The FERC has neither imposed nor forbidden any particular operating condition For the moment, the pipelines are considered the most capable of coordinating the actions of all the involved buyers and sellers with the physical limitations of the pipeline systems

If any customer class is expected to experience a rate increase of 10 percent or more under the new rate design, the pipeline must phase in the rate increase over no more than four years A pipeline is allowed to recover all of its "prudently incurred" costs associated with implementing the rule The rule identifies, and provides rules for recovering, four types of transition costs

(1) Unrecovered gas costs remaining in Account 191 can be directly billed to former firm sales customers

(2) Costs related to restructuring existing gas supply contracts can be recovered through a negotiated "exit fee" or a reservation charge on throughput

(3) The costs of assets used for sales service that are no longer recoverable from unbundled transport customers can potentially be recovered through a general rate case filing

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(4) Costs of assets needed to implement Order No 636 (such as meters, valves, and supervisory control and data acquisition pipeline monitoring system costs) can be filed for recovery in a general rate case

Order No 636 did not include the "small customer exemption" that was under consideration during the mega-NOPR proceedings This exemption would have allowed small volume customers to continue to receive a fully bundled sales and transportation service The provision was dropped from the final rule because small customers " can be served reliably through a combination of unbundled sales and the no-notice transportation service required by this rule "

In August 1992, the FERC, in an effort to protect the interests of small gas customers and in response to numerous requests for a rehearing of Order No 636, issued Order No 636-A Order No. 636-A made minor modifications to Order No 636, but generally reaffirmed its provisions Below are the more significant changes made by Order No 636-A

(1) Pipelines are required to maintain their existing one-part volumetric rates, computed using existing load factors to determine the transportation rates for small customers

(2) Small customers are given a transition period Under the transition, a pipeline is required to continue to sell gas to its current customers using cost-based rates The requirement lasts for one year from the effective date of the blanket sales certificate granted the pipeline under Order No 636

(3) Capacity releases for periods of less than one month are permitted without prior posting on the electronic bulletin board or bidding for the released capacity

(4) While continuing to prefer the SFV method for rate design and cost allocation purposes, the FERC will allow parties in restructuring proceedings to consider using other techniques to distribute revenue responsibility among customers, such as through the use of seasonal contract quantities or entitlements

(5) Pipelines are required to recover 10 percent of gas supply realignment costs from interruptible transportation customers

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In November 1992, the FERC issued Order No 636-B which denies requests for a rehearing of Order No 636-A Order 636-B did, however, provide additional clarification of issues raised in Order Nos 636 and 636-A In January 1993, the FERC denied all requests for a rehearing of Order No 636-B and, thus, will issue no further rehearing orders in the Order No 636 rule-making proceeding

Natural gas currently provides about 10 percent of the fuel input of electric power generators. Since the mid-1970s, electric utilities have shunned natural gas because of legislative barriers, price uncertainty, and a perceived lack of reliability in a fuel that is difficult to inventory and generally arrives to customers "just in time" Gas, however may grow in importance as a generating fuel over the next ten to 15 years as electric utilities take advantage of the benefits of natural gas Advantages of natural gas include its ability to burn cleanly and efficiently, thereby helping the electric utilities comply with clean air legislation and national energy strategy Another advantage of natural gas is that domestic supplies are abundant

Although the new market structure is expected to help promote competitively priced gas supplies, Order No 636 could complicate the market because of the broad variety of gas supply and storage options that will be available

The industry restructuring initiated by Order No 636 is expected to increase the availability of many unbundled supply, transportation, and storage options to all market participants Although Order No 636 must still withstand the challenges of implementation, the FERC has made a firm step toward an unbundled and more competitive natural gas marketplace

The concept of unbundling of gas service has extended beyond interstate pipelines Many state regulators now permit local distribution centers (LDCs) to unbundle services to large industrial customers These customers may use the transportation service provided by the LDC, while purchasing gas from another source

§ 20.06 Stranded Costs

The issue of stranded costs affects different segments of the public utility industry to varying degrees as they move toward competition and deregulation A stranded cost is the portion of any prudent investment, deferred cost, or commitment, not yet paid for by a

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customer choosing to leave a utility's system, which was made to serve that customer during a period when regulatory statutes imposed a requirement to serve it at a regulated price

Stranded costs could, potentially, be recovered customers (exiting customers or customers remaining with the utility), shareholders, or some combination of the two Recovery of stranded costs from exiting or continuing customers is not a new concept, many arguments support such recovery The Federal Energy Regulatory Commission (FERC) has recognized the need for utilities to recover stranded costs FERC Order No 636, for example, allowed natural gas pipelines to recover from pipeline customers, prudently incurred costs that otherwise would not have been recovered because of the switch from bundled to unbundled service This same concept is embraced in the FERC's 1995 supplemental notice of proposed rulemaking (NOPR) on open-access and stranded costs

Costs often become stranded when an industry becomes deregulated, but can also become stranded when an industry becomes regulated An example of an industry faced with stranded costs from regulation was provided in 1994 when the cable television industry was faced with the possibility that some of the costs of acquiring cable systems before regulation would not be recoverable in cost-of-service ratemaking The Federal Communications Commission (FCC) concluded that goodwill, including going-concern value of an acquired company, should be presumptively disallowed from the rate base because it, likely, represented expectations of "supra-competitive" profits that should not be borne by regulated service customers Cable operators were forced to justify inclusion of these costs in the rate base, to the extent that their inclusion produced rates above competitive levels

An example of costs being stranded from deregulation is found currently in the electric industry where the potential for stranded costs is substantial This is because the industry's generation facilities are capital intensive and because, to prevent rate spikes, regulators have often deferred the recovery of major project costs over a period of years Costs that could be stranded for the electric utilities include

- costs of generating units that may be abandoned in the face of more efficient technology or due to the loss of system customers to competitive power sources,
- deferred regulatory assets (see § 20 08[3]),

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- parts inventories and fuel inventories for plants whose costs are determined to be stranded, and
- commitments for purchased power, leases, and fuel supply reserves that are no longer needed to serve customers

In July 1994, the FERC addressed the question of stranded costs for electric utilities in a Notice of Proposed Rulemaking (NOPR) In that NOPR, the FERC took no position on the issue of stranded costs for retail customers, saying that state regulatory bodies should address the issue of retail stranded costs The FERC did, however, take the position that wholesale customers who were to benefit from a utility's costs should pay for their recovery if those costs become stranded The NOPR suggests that exit provisions to address recovery of stranded costs should be included in all future wholesale requirements contracts and should be renegotiated into all existing ones In limited circumstances, the FERC proposes to allow recovery of verifiable stranded costs through transmission rates or, for cases in which existing contracts cannot be renegotiated, to enforce contract amendments filed unilaterally by the utility

In the process of obtaining market-based rates for wholesale power sales, several utilities have filed open-access transmission tariffs with the FERC In these situations, the FERC has permitted an open-access provider to include provisions in its tariff to recover stranded costs associated with wholesale customers who continue to use the open-access provider's transmission lines but choose to purchase power from a different source In a July 1994 decision involving an open-access tariff, the United States Circuit Court of Appeals ruled that recovering stranded costs from customers leaving a utility's system may be anticompetitive, and it remanded the case to the FERC for further evidentiary hearings This decision may be viewed as narrowly addressing a particular tariff that was approved by the FERC before it published its NOPR

The 1994 stranded cost NOPR was succeeded by a supplemental notice of proposed rulemaking (supplemental NOPR) in 1995 (see § 20 02[1][b]) The supplemental NOPR, also sometimes referred to as the mega-NOPR or giga-NOPR, was the result of the feedback received on the original stranded cost NOPR and an effort to coordinate the FERC's actions on stranded costs with its actions on the related subject of open access

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In the supplemental NOPR, the FERC stated its belief that, "the approach proposed in the Stranded Cost NOPR should adequately cover most, if not all, costs that could be stranded in an environment where transmission access is more widely available, including the access environment that the Commission expects if the provisions of the Open Access NOPR are adopted" The supplemental NOPR set forth a number of preliminary determinations which were reached through the original NOPR process

The FERC made a preliminary determination that "recovery of legitimate and verifiable stranded costs should be allowed, and that direct assignment of stranded costs to departing customers, as proposed in the Stranded Cost NOPR, is the appropriate method for recovery" In setting out its reasons for this conclusion, the FERC noted that, "Public utilities have invested billions of dollars in facilities built under a regulatory regime in which they have been permitted to recover all prudently incurred costs " adding that, "We believe that utilities should be allowed to recover the costs incurred under the old regulatory regime according to the expectations of cost recovery established under that regime "[15] The FERC argued that alternatives to the direct assignment method for allocating stranded costs (i e to do nothing or broadly allocate costs among all customers) were in violation of its long standing cost causation principle

The FERC made a preliminary determination, reaffirming its proposal from the June 29, 1994, NOPR, that utilities not be allowed to seek recovery of stranded costs associated with contracts entered into after July 11, 1994, except through the specific stranded cost provisions contained in those contracts The FERC also reaffirmed its position that recovery of stranded costs associated with these new contracts will not be allowed through any transmission rates under sections 205, 206, or 211 of the FPA

The FERC made a preliminary determination that recovery of stranded costs associated with contracts executed before July 11, 1994, that do not contain exit fees or other explicit stranded cost provisions, should also be allowed and continued to encourage the parties to negotiate appropriate stranded cost provisions as amendments to their contracts The FERC abandoned its proposed three-year negotiation period, however, and proposed instead that "(1) a public utility or its customer under the contract may, at any time prior to the expiration

[15] Dkt No RM 94-7

of the contract, file a proposed stranded cost amendment to the contract under section 205 or 206, or (2) a public utility may, at any time prior to the expiration of the contract, file a proposal to recover stranded costs through transmission rates for a departing customer "[16] This determination also included provisions reaffirming the FERC's requirements relating to evidentiary documentation and mitigation by utilities seeking to recover stranded costs

The FERC made a preliminary determination that "it is appropriate to leave it to state regulatory authorities to assume responsibility for any stranded costs occasioned by retail wheeling, except in the narrow circumstance in which the state regulatory authority does not have authority under state law, at the time retail wheeling is required, to address recovery of such costs "[17] In making this determination, FERC emphasized that they "continue to be of the opinion that utilities are entitled, from both a legal and policy perspective, to an opportunity to recover their past prudently incurred costs " and added that the FERC holds a "strong expectation" that the states will provide for full recovery of all legitimate and verifiable stranded costs The FERC concluded that claims for recovery of stranded costs arising when a retail customer becomes a wholesale customer and leaves a utility's system through the process of municipalization should be directed to FERC FERC-jurisdictional transmission rates will be adjusted to provide recovery in these cases The FERC cautioned, however, that, except in the case of municipalization, it will not allow recovery of retail stranded costs through interstate transmission rates

In addition to the above preliminary determinations in the supplemental NOPR, the FERC proposed procedures to provide an existing wholesale requirements customer who is contemplating switching suppliers, but continuing to use the existing supplier's transmission system, with advance notice of how the utility would propose to calculate the resulting stranded costs These procedures are as follows

- The customer may request the calculation of the maximum exposure without mitigation or the formula that the utility would use to make such a calculation
- The utility must provide the computed maximum exposure without mitigation or the formula to be used to compute the

[16] *Id*

[17] *Id*

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stranded cost amount, with appropriate support for each element in the formula The utility should provide its rationale for its estimate of how long it expected to keep the customer and how it intends to mitigate stranded costs

- If the customer believes that the utility failed to establish a reasonable expectation of continuing to serve the customer, or that the proposed maximum stranded cost charge (or formula) is unreasonable, it has thirty days to respond The parties should then attempt to reach an agreeable charge within a reasonable period of time
- If the parties are unable to resolve the matter, the customer may either (1) file a complaint with the FERC seeking determination of the issues, or (2) contest the charge when it is filed under Section 205

The Supplemental NOPR also proposes to change the definition of "wholesale stranded cost" to include specific reference to stranded costs resulting from municipalization The new definition would be "any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to (i) a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or (ii) a retail customer, or a newly created wholesale power sales customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility "

In addition to direct asset costs, recoverable stranded costs may include numerous investments, expenses and future costs Examples include

- construction work in progress,
- regulatory assets such as phase-in amounts for new plant, post-retirement benefit other than pension costs, pension plan deferrals, and tax normalization,
- nuclear decommissioning costs,
- deferred fuel costs pending recovery via FAC mechanisms,
- social programs such as DSM, low income assistance, and research and development projects,
- Clean Air Act compliance costs,

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- storm damage expenses, and
- other unknown future liabilities (the authors believe these would include such items as purchased power contract obligations and lease commitments)

Under the new rules, the FERC would require stranded costs to be measured by the "revenues lost" approach rather than an asset-by-asset approach The "revenues lost" approach measures the recoverable stranded costs as the difference between revenues expected from a customer under traditional regulation and the expected revenues in a competitive market

The FERC's proposed "revenues lost" method requires the utility to calculate a customer's stranded cost by subtracting the competitive market value of the power the customer would have purchased from the utility (and the basic revenues from the transmission service) from the revenues that the customer would have paid the utility, had the customer continued to take service under its contract The utility, however, must attempt to mitigate stranded costs by marketing stranded power supplies

On the issue of jurisdiction over transmission, the FERC noted that the distinction between FERC-jurisdictional transmission and state-jurisdictional local distribution was important for three reasons

(1) Facilities that can be used for wholesale transmission in interstate commerce would be subject to the FERC's open access requirements

(2) States may, through their jurisdiction over facilities used in local distribution, impose a surcharge on local distribution that will permit recovery of stranded costs resulting from retail wheeling or retail-turned-wholesale customers

(3) To meet state and federal statutory filing requirements, utilities need to know which regulator has jurisdiction over which facilities

Because of the absence of a clear distinction between transmission and local distribution facilities, the FERC, based on case law and practical realities, concluded that both functional and technical characteristics should be used to determine whether a facility is a local distribution facility Indicators to be used include

- Local distribution facilities are normally in close proximity to retail customers

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- Local distribution facilities are primarily radial in character
- Power rarely if ever, flows out of local distribution facilities
- After enter a local distribution system, power is not reconsigned or transported to some other market
- Power entering a local distribution system is consumed in a comparatively restricted geographical area
- Meters are based at the transmission/local distribution interface to measure flows into the local distribution system
- Local distribution systems are of reduced voltage

For unbundled wholesale wheeling, a functional test will be applied and the only issue will be whether the power is delivered to a lawful wholesaler For unbundled retail wheeling, a combination functional-technical test (that will take into account technical characteristics of facilities used) will be applied

As deregulation of the public utility industry develops, the debate over who should pay for the stranded costs will continue Ultimately, federal and state regulators and legislators will be required to address the stranded cost issue

§ 20.07 Future of Public Utility Regulation

Predicting what the future may hold for public utility regulation is a difficult task Many interrelated factors can cause quick, and often abrupt, changes in regulatory philosophy and in the mode of operation of the various regulatory agencies These factors include

(1) the political philosophy of those in power in the federal government and in the various states,

(2) the overall economic situation facing the United States at a given time, including the perceived national energy situation and level of foreign competition, and

(3) new and changing technology in the utility industry, such as the development of alternative energy sources and advances in telecommunications and electric generation

In light of the factors potential affecting utility regulation, only general predictions of future regulatory trends can be made Surely, some form of regulation over ratemaking, service, accounting, and financing will continue at both the federal and state levels Continued

experimentation and change in techniques for regulation of ratemaking can also be expected Experimentation and change are especially likely for theoretical issues such as cost-of-service, components of the rate base, efficient rate design, and methods of determining an allowed rate of return on equity

Overall regulation of utilities outside of the ratemaking area has, in all probability, reached its peak for at least the immediately foreseeable future The current trend toward reassessing the effectiveness and efficiency of regulation is likely to affect regulations designed for a public utility's service company subsidiaries Regulation of energy supplies and prices can be expected to decrease, as supply and demand determine the commodity cost of basic energy sources such as oil, gas, and coal Experimentation with deregulating components of the vertically integrated utility business will continue and may result in wholesale deregulation of some components, such as electric generation The Energy Policy Act of 1992 has already removed a number of impediments to deregulation of wholesale electric generation The trend to deregulate telephone operations also appears likely to continue With the vast improvements in telecommunications technology, certain forms of competition may provide greater benefits to the consumer

Finally, a movement is underway to allow utilities to diversify into unregulated businesses Central to this complicated and controversial issue is the Public Utility Holding Company Act (PUHCA) A number of bills have been introduced in recent sessions of Congress to significantly modify or to repeal PUHCA The Securities Exchange Commission has gone on record in favor of repeal

In summary, as technology continues to improve, utility operations that were formerly considered natural monopolies may become better suited to limited competition If this competitive trend becomes a reality, regulators and elected officials will have to reevaluate the current system of public utility regulation

§ 20 08 Analysis of FASB Statement No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of FASB Statement No. 71" (December 1988)

As competition continues to increase in the utility industry, through deregulation of certain industries and changes in the method of

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regulating others, growing numbers of utilities are finding that that they no longer meet the criteria to apply Financial Accounting Standards Board (FASB) Statement No 71 The methods used to account for di' itinuing the use of Statement No 71 have varied

In July 1988 e FASB .ssued a proposed accounting standard that would provide .uidance for discontinuation of Statement No 71 Like the FASB's proposals for abandonments, disallowances, and phase-in plans, this ex 'sure draft was the subject of much debate within the utility indust: .nd the accounting profession

In December 1988, the FASB issued Statement No 101, "F :ulated Enterprises — Accounting for the Discontinuation of Application of FASB Statement No 71 " The important aspects of Statement No 101 are discussed below

[1] Accounting Requirements

Statement No 101 requires that utilities discontin. application of FASB Statement No 71, "Accounting for the Effects of Certain Types of Regulation," if they no longer meet the three criteria for its application presented in paragraph 5 of the statement Statement No 101 provides examp·es of situations in which a utility's operations would fail to meet the criteria, including the following

(1) deregulation,

(2) a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, this example is fairly broad, dep ·ing on the facts ·nd circumstances, it might be ir oreted to include regulatory scheme in which a ut. y is not regulated, b. .d on its specific costs, for example

(a) pricing new power, based on the average price of electricity in a given region,

(b) pricing that reflects the cost of competitive alternatives at the time generating capacity comes on-line or that fluctuates with the price of competitive alternatives over time,

(c) creation of zones of flexibility in which the utility may charge any price the market can bear,

(d) "value-based" output pricing intended to approximate market pricing, and

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(e) pricing based on the "avoided cost" of the purchaser;

(3) increasing competition that limits the utility's ability to sell services or products at rates that will recover costs, and

(4) regulatory actions, resulting from resistance to rate increases, that limit the utility's ability to sell services or products at rates that will recover costs, if the utility is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts

The term "costs" in these examples is used consistently with its usage in paragraph 5 of FASB Statement No 71 (which the board has indicated refers to allowable costs) In addition to the examples provided in Statement No 101, the identification of a significant asset impairment under the provisions of FASB Statement No 121 (see § 12 05), may also be an event that would indicate the need for an entity to assess its continuing application of FASB Statement No 71

Although the examples from FASB Statement No 101 provide some guidance, they also raise questions about the FASB's intent for practices that have been commonplace in the utility industry Guidance in Statement No 101 is unclear, for example, on settlement agreements that permit recovery of costs and a reasonable return, but do not follow cost-based rate-making, and temporary excess capacity disallowances not based on issues of imprudence

If a separable portion of the utility's operations within a regulatory jurisdiction no longer meets the Statement No 71 criteria, application of Statement No 71 for that separable portion must be discontinued This situation creates a refutable presumption that application of Statement No 71 should be discontinued for all of the utility's operations within that regulatory jurisdiction Statement No 101 does not define the term separable portion but refers to paragraph 6 of Statement No 71 and states that a separable portion may be a utility's operations only within a regulatory jurisdiction or a smaller portion (such as a customer class within a regulatory jurisdiction) (See § 20 08[4][c])

An entity that discontinues application of Statement No 71 must report this change It also must eliminate from its statement of financial position the effects of any actions of regulators which resulted in

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recognizing assets and liabilities, pursuant to Statement No 71, that would not have been recognized by businesses, in general However, if the entity has the right to receive payment or the obligation to pay exists because of past events or transactions, regardless of future transactions, it should not eliminate these assets or liabilities

An exception is made for the carrying amounts of plant, equipment, and inventory These balances may not be adjusted unless the assets are impaired, in which case their carrying amounts must be reduced to reflect that impairment Thus, neither the allowance for funds used during construction nor intercompany profit may be eliminated, nor may disallowances of costs of recently completed plants be restored However, if any other amounts that would not be includable in the carrying amounts of plant, equipment, or inventory by businesses, in general, (such as post-construction operating costs capitalized pursuant to paragraph 9 of Statement No 71 or the cumulative difference, if any, between recorded depreciation and depreciation recorded using a generally accepted method of depreciation) are included in or netted against the carrying amounts of plant, equipment, or inventory, those amounts must be eliminated The FASB had previously been deadlocked over the question of whether to permit utilities to opt for remeasurement Some board members did not believe that adjustments to the carrying amounts of these assets were appropriate, absent impairment Others believed that remeasurement was conceptually correct but that the advantages of prescribing a consistent method outweighed their concerns about prohibiting a conceptually correct approach For these reasons, the board concluded that it should not permit utilities discontinuing application of Statement No 71 to adjust the carrying amounts of plant, equipment, and inventory to the amounts that would have been recorded if Statement No 71 had never been applied

Some concern was expressed that a rate-regulated utility might attempt to avoid certain accounting requirements of FASB Statement No 71, as amended by FASB Statement No 90, by deciding to discontinue application of Statement No 71 In stating its basis for its conclusions, the FASB stressed that Statement No 101 in no way modifies Statement No 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs " Thus, application of Statement No 71, as amended by Statement No 90, is not optional If a utility meets the criteria for application of Statement No 71, its operations must be reported consistent with those requirements

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The effect of the adjustments made to reflect discontinuance, net of any related tax effects, must be included in income of the period of the change and classified as an extraordinary item The discontinuation of application of Statement No 71 may not, in some circumstances, meet the criteria in paragraph 20 of Accounting Principles Board (APB) Opinion No 30 for an extraordinary item Statement No 101 amends APB Opinion No 30 so that the net effect of discontinuing the application of Statement No 71 is an extraordinary item without regard to the criteria in paragraph 20 of the opinion

For the period in which discontinuation is reflected, the utility must disclose the reasons for the discontinuation and identify the portion of its operations for which the application of Statement No 71 is being discontinued A financial statement that is restated must disclose the nature of the restatement and its effect on income before extraordinary items, net income, and related per share amounts for each period restated

Statement No 101 does not address the accounting for reapplication of Statement No 71 by a utility that had previously discontinued application of Statement No 71 for all or a portion of its operations

[2] Effective Date

FASB Statement No 101 is effective for discontinuations of application of Statement No 71 that occur in fiscal years ending after December 15, 1988 The statement provides transition rules for discontinuations occurring in 1988 or 1989 It is prohibited to restate interim or annual financial statements for periods that ended before the date of discontinuation of Statement No 71

[3] Financial Accounting and Regulatory Implications

The following are potential financial statement effects of applying the accounting procedures of FASB Statement No 101

(1) regulatory assets and liabilities would have to be written off, including

(a) deferred assets recorded in connection with plant abandonments,

(b) phase-in deferrals,

(c) storm damage reserves and other self-insurance reserves,

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(d) regulatory assets associated with additional income tax deferrals recorded under FASB Statement No 109,

(e) assets and liabilities recorded to reflect differences between net periodic pension and other post retirement benefit costs for ratemaking purposes and the amounts determined under FASB Statements No 87 and 106,

(f) deferrals related to over- and under-recoveries of fuel costs, and

(g) other deferrals relating to gains or losses on sale of plant and reacquisition of debt, early retirement programs, and demand-side management programs,

(2) capital lease expense would be accounted for as specified in FASB Statement No 13, and use of operating lease treatment in the income statement for capital leases, permitted by Statement No 71, would no longer apply, and

(3) depreciable lives and methods might require adjustment

The financial effects of adopting Statement No 101 would be widespread Among those that are readily foreseeable are the following

(1) reduced retained earnings, which will affect payment of dividends,

(2) a changed book income component for calculating the alternative minimum tax, and

(3) a changed income component for calculating SEC and other financial coverage ratios

Some regulatory effects are also certain for utilities that have separable portions of their businesses that continue to be subject to cost-based regulation or that are subject to some form of continuing regulation that is cost based These regulatory effects might include (1) a changed capital structure used for allowance for funds used during construction (AFUDC) and rate base return calculations, and (2) a perception of excessive earnings due to differences in amount and period of recording revenues and expenses for regulatory and financial purposes

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[4] General Criticisms

The FASB's statement on the accounting when a utility discontinues the application of Statement No 71 to all or a part of its operations was generally appropriate The FASB was correct in deciding not to specify when a utility should stop applying Statement No 71 The issuance of Statement No 101, however, has raised many concerns, such as

(1) the examples used to illustrate when discontinuation would be appropriate are not readily understandable,

(2) the term "costs" is not defined, and

(3) "separable portion" is not adequately defined

[a] Guidance on When to Discontinue

The FASB was correct to refrain from stating in detail criteria that would prevent a utility from continuing to apply Statement No 71 The FASB also should have refrained from providing examples to guide utilities on when to discontinue using Statement No 71 The examples create more confusion than clarification Determining whether to discontinue application of Statement No 71 often requires an evaluation of a wide variety of facts and circumstances, some of which are unique to the particular utility The decision to discontinue application of Statement No 71 should continue to be made on the basis of judgment rather than on a set of detailed criteria or a list of broad, vague examples

In recent years, for example, regulators have ordered temporary disallowances of plant costs in connection with findings of excess capacity In addition, some electric utilities have been ordered to remove temporarily (or have voluntarily removed) from service and from their rate bases, electric generating plants that were previously in service Although many of the disallowances, directly or indirectly, involved newly completed plants, the disallowances have, typically, been ordered without a finding that the utility should not have constructed, or should have delayed constructing, the new capacity In accordance with paragraph 60 of Statement No 90, utilities that have received such orders have not recorded the indirect disallowances of plant costs However, paragraph 60 of Statement No 90 suggests that an "excess capacity" disallowance ordered without a specific finding of imprudence raises questions about whether the utility

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continues to meet the criteria for application of Statement No 71 The language of the basis for conclusions of Statement 90, if compared with the examples in Statement No 101, may lead some to conclude that a temporary excess capacity disallowance should, by itself, cause the utility to discontinue applying Statement No 71 to all or a portion of its operation

This conclusion would be unwarranted in most instances Temporary excess capacity decisions are typically based on legal, rather than economic, considerations It is unlikely that the FASB intends that, under Statement No 101, the existence of temporary disallowances should be enough to be the sole reason for discontinuing application of Statement No 71

[b] Definition of Costs

The FASB has indicated that the term "cost," as used in the examples of when to discontinue application of Statement No 71, refers to allowable costs The FASB's decision, to require discontinuance of application of Statement No 71 when rates are established to specifically recover all incurred costs of a regulated utility but not sufficient to generate a future equity return, is questionable

The FASB's position seems inconsistent In discussing what "cost" a utility may defer under Statement No 71, the FASB has, with the exceptions of AFUDC equity and phase-in deferrals, consistently taken the position that "cost" refers to incurred cost [14] The following question arises Why, in determining whether a utility can apply Statement No 71, must it be recovering allowable costs in all instances?

[c] Failure to Define Separable Portion

Statement No 101 does not define the term "separable portion" Instead, it indicates that separable portion may refer to a utility's operations within a regulatory jurisdiction or a smaller portion (such as a customer class within a regulatory jurisdiction) This approach will, ultimately, create several problems in applying Statement No 101

The failure to define separable portion may inappropriately lead utilities to consider whether certain segments of their businesses have

[14] See § 4 04[5] for additional discussion of the AFUDC equity component.

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been deregulated in isolation from the dynamics of the ratemaking process as a whole Because a utility's rates for a particular class of customers appear to be based on something other than the specific cost of providing service to those customers, it cannot be concluded that a separable portion of the utility's business has been deregulated The regulator may have, in the ratemaking process, considered the cost of providing service elsewhere Instances may occur, for example, in which the ratemaking process has resulted in residential rates being partially subsidized through industrial rates, perhaps because of the greater political sway that residential customers hold in rate hearings

On the other hand, especially for large, expensive generating units that have recently come on-line, industrial rates may have been discounted to the point that they do not cover the full cost of providing service This situation usually results from concerns that the industrial customers will leave the utility's system, forcing remaining customers to cover even greater costs Although either of these situations may appear to fit the examples of circumstances in which discontinuation is appropriate, this conclusion would not necessarily be justified because a reallocation of costs through the ratemaking process has occurred As long as the regulator provides rates that allow the utility to recover its full specific costs on an overall basis d scontinuance for a particular customer class would, in most cases, be inappropriate

Utilities must approach the separable portion issue with considerable caution and skepticism It is difficult to conclude that, within a regulatory jurisdiction and in considering the dynamics of ratemaking, certain customers or assets are not regulated and, more importantly, do not affect the rates charged other customers and the regulatory returns a utility is allowed to earn A utility must generally judge whether it meets the requirements of Statement No 71 The accounting and reporting generated by separating portions of plants or classes of customers is uncertain and confusing The authors doubt that this accounting, if implemented, will have long-term acceptance

The FASB's failure to define separable portion leads to some practical problems in carrying out Statement No 101 If a utility does conclude that a particular customer class within a regulatory jurisdiction has been deregulated, how does it identify the costs that are related to that customer class and, therefore, subject to adjustment under Statement No 101? In addition, what is the appropriate accounting in subsequent periods if load shifts between customer classes lessens

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that part of the utility's assets devoted to serving the deregulated customer class?

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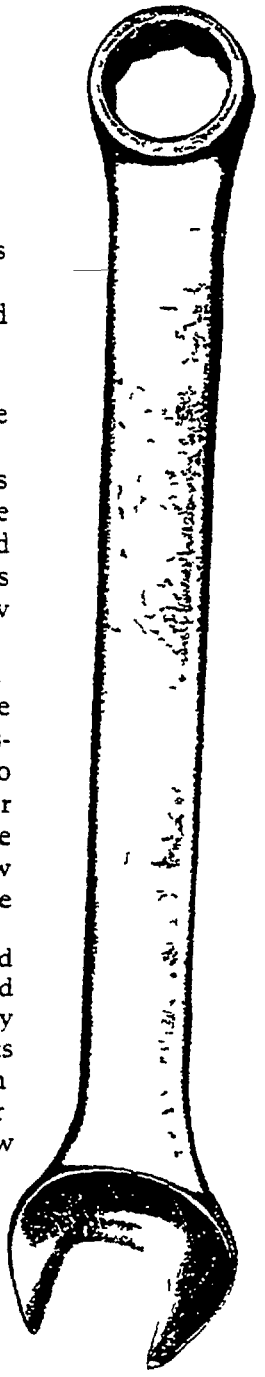
Redesigning the corporation requires a new set of tools and concepts

The **Information**

by Peter F Drucker



Ever since the new data processing tools first emerged 30 or 40 years ago, business people have both overrated and underrated the importance of information in the organization We – and I include myself – overrated the possibilities to the point where we talked of computer-generated "business models" that could make decisions and might even be able to run much of the business But we also grossly underrated the new tools, we saw in them the means to do better what executives were already doing to manage their organizations

Nobody talks of business models making economic decisions anymore The greatest contribution of our data processing capacity so far has not even been to management It has been to operations – for example, computer-assisted design or the marvelous software that architects now use to solve structural problems in the buildings they design

Yet even as we both overestimated and underestimated the new tools, we failed to realize that they would drastically change the *tasks* to be tackled Concepts and tools, history teaches again and again are mutually interdependent and interactive One changes the other That is now happening to the concept we call a business and to the tools we call information The new tools enable us – indeed may force us – to see our businesses differently

- as generators of resources, that is, as organizations that can convert business costs into yields,
- as links in an economic chain, which managers need to understand as a whole in order to manage their costs,
- as society's organs for the creation of wealth, and
- as both creatures and creators of a material environment, the area outside the organization in which opportunities and results lie but in which the threats to the success and the survival of every business also originate

This article deals with the tools executives require to generate the information they need And it deals with the concepts underlying those tools Some of the tools have been around for a long time, but rarely, if ever, have they been focused on the task of managing a business Some have to be refashioned in their present form they no longer work For some tools that promise to be important in the future, we have so far only the briefest specifications The tools themselves still have to be designed

Even though we are just beginning to understand how to use information as a tool, we can outline with high probability the major parts of the information system executives need to manage their businesses So, in turn, can we begin to understand the concepts

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Executives Truly Need

likely to underlie the business – call it the re designed corporation – that executives will have to manage tomorrow

From Cost Accounting to Yield Control

We may have gone furthest in redesigning both business and information in the most traditional of our information systems accounting In fact, many businesses have already shifted from traditional cost accounting to *activity based cost ing* Activity based costing represents both a differ ent concept of the business process especially for manufacturers, and different ways of measuring

Traditional cost accounting, first developed by General Motors 70 years ago, postulates that total manufacturing cost is the sum of the costs of in dividual operations Yet the cost that matters for competitiveness and profitability is the cost of the total process and that is what the new activity based costing records and makes manageable Its basic premise is that manufacturing is an inte grated process that starts when supplies materials and parts arrive at the plant's loading dock and con tinues even after the finished product reaches the end user Service is still a cost of the product, and so is installation even if the customer pays

Traditional cost accounting measures what it costs to *do* a task, for example to cut a screw thread Activity based costing also records the cost of *not doing* such as the cost of machine downtime, the cost of waiting for a needed part or tool, the cost of inventory waiting to be shipped and the cost of reworking or scrapping a defective part The costs of not doing, which traditional cost accounting cannot and does not record, often equal and sometimes even ex ceed the costs of doing Activity-based costing therefore gives not only much better cost control but increasingly, it also gives *result control*

Traditional cost accounting assumes that a cer tain operation – for example heat treating – has to be done and that it has to be done where it is being done now Activity-based costing asks Does it have to be done If so, where is it best done Activity based costing integrates what were once several activities – value analysis, process analysis, quality management, and costing – into one analysis

Using that approach, activity-based costing can substantially lower manufacturing costs – in some instances by a full third or more Its greatest im pact however is likely to be in services In most manufacturing companies cost accounting is in adequate But service industries – banks retail stores hospitals, schools newspapers and radio and television stations – have practically no cost in formation at all

Activity based costing shows us why traditional cost accounting has not worked for service compa nies It is not because the techniques are wrong It is because traditional cost accounting makes the wrong assumptions Service companies cannot start with the cost of individual operations as

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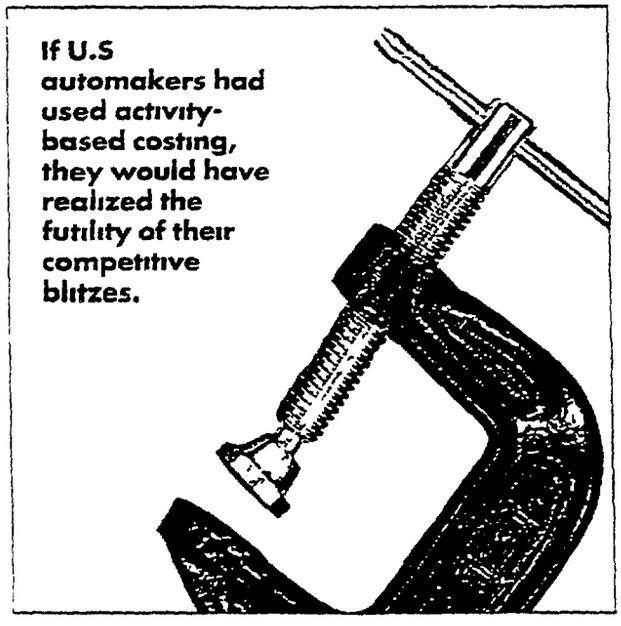

manufacturing companies have done with traditional cost accounting They must start with the assumption that there is only *one* cost that of the total system And it is a fixed cost over any given time period The famous distinction between fixed and variable costs, on which traditional cost accounting is based, does not make much sense in service Neither does the basic assumption of traditional cost accounting that capital can be substituted for labor In fact, in knowledge based work especially, additional capital investment will likely require more rather than less labor For example a hospital that buys a new diagnostic tool may have to add four or five people to run it Other knowledge based organizations have had to learn the same lesson E all costs are fixed over a given time period a resources cannot be substituted for one an- c that the *total* operation has to be costed t re precisely the assumptions with which activity-based costing starts By applying them to services we are beginning for the first time to get cost information and yield control

Banks for instance, have been trying for several decades to apply conventional cost accounting techniques to their business – that is, to figure the costs of individual operations and services – with almost negligible results Now they are beginning to ask Which one *activity* is at the center of costs and of results The answer serving the customer The cost of a customer in any major area of banking is a fixed cost Thus it is the *yield* per customer – both the volume of services a customer uses and the mix of those services that determines costs and profitability Retail discounters especially those in Western Europe have known that for some time They assume that once a unit of shelf space is installed, the cost is fixed and management consists of maximizing the yield thereon over a given time span Their focus on yield control has enabled them to increase profitability despite their low prices and low margins

Service businesses are only beginning to apply the new costing concepts In some areas such as research labs, where productivity is nearly impossible to measure, we may always have to rely on assessment and judgment rather than on measurement But for most knowledge based and service work, we should, within 10 to 15 years have developed reliable tools to measure and manage costs and to relate those costs to results

Thinking more clearly about costing in services should yield new insights into the costs of getting and keeping customers in all kinds of businesses If GM Ford and Chrysler had used activity-based costing, for example, they would have realized early on the utter futility of their competitive blitzes of the past few years, which offered new-car buyers spectacular discounts and hefty cash rewards Those promotions actually cost the Big Three automakers enormous amounts of money and worse, enormous numbers of potential customers In fact, every one resulted in a nasty drop in market standing But neither the costs of the special deals nor their negative yields appeared in the companies' conventional cost accounting figures so management never saw the damage Conventional cost accounting shows only the costs of individual manufacturing operations in isolation and those were not affected by the discounts and rebates in the marketplace Also conventional cost accounting does not show the impact of pricing decisions on such things as market share

Activity based costing shows – or at least attempts to show – the impact of changes in the costs and yields of every activity on the results of the whole Had the automakers used it it soon would have shown the damage done by the discount blitzes In fact, because the Japanese already use a form of activity based costing – though still a fairly primitive one – Toyota, Nissan and Honda knew better than to compete with U S automakers through discounts and thus maintained both their market share and their profits

From Legal Fiction to Economic Reality

Knowing the cost of your operations however, is not enough To succeed in the increasingly competitive global market, a company has to know the

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costs of its entire economic chain and has to work with other members of the chain to manage costs and maximize yield Companies are therefore beginning to shift from costing only what goes on inside their own organizations to costing the entire economic process, in which even the biggest company is just one link

The legal entity, the company, is a reality for shareholders, for creditors for employees, and for tax collectors But *economically* it is fiction Thirty years ago, the Coca Cola Company was a franchisor Independent bottlers manufactured the product Now the company owns most of its bottling operations in the United States But Coke drinkers – even those few who know that fact – could not care less What matters in the marketplace is the economic reality, the costs of the entire process, regardless of who owns what

Again and again in business history, an unknown company has come from nowhere and in a few short years overtaken the established leaders without apparently even breathing hard The explanation always given is superior strategy, superior technology, superior marketing, or lean manufacturing But in every single case the newcomer also enjoys a tremendous cost advantage, usually about 30% The reason is always the same the new company knows and manages the costs of the entire economic chain rather than its costs alone

Toyota is perhaps the best publicized example of a company that knows and manages the costs of its suppliers and distributors they are all of course members of its *keiretsu* Through that network Toyota manages the total cost of making, distributing, and servicing its cars as one cost stream putting work where it costs the least and yields the most

Managing the economic cost stream is not a Japanese invention however but a U S one It began with the man who designed and built General Motors William Durant About 1908 Durant began to buy small successful automobile companies – Buick Oldsmobile Cadillac Chevrolet – and merged them into his new General Motors Corporation In 1916 he set up a separate subsidiary called United Motors to buy small successful parts companies His first acquisitions included Delco which held Charles Kettering's patents to the automotive self starter

Durant ultimately bought about 20 supplier companies his last acquisition – in 1919, the year before he was ousted as GM's CEO – was Fisher Body Durant deliberately brought the parts and accessories makers into the design process of a new automobile model right from the start Doing so allowed him to manage the total costs of the finished car as one cost stream In fact, Durant invented the keiretsu

However, between 1950 and 1960, Durant's keiretsu became an albatross around the company's neck, as unionization imposed higher labor costs on GM's parts divisions than on their independent competitors As the outside customers, the independent automobile companies such as Packard and Studebaker, which had bought 50% of the output of GM's parts divisions, disappeared one by one, GM's control over both the costs and quality of its main suppliers disappeared with them But for 40 years or more, GM's systems costing gave it an unbeatable advantage over even the most efficient of its competitors, which for most of that time was Studebaker

Sears, Roebuck and Company was the first to copy Durant's system In the 1920s, it established long term contracts with its suppliers and bought minority interests in them Sears was then able to consult with suppliers as they designed the product and to understand and manage the entire cost stream That gave the company an unbeatable cost advantage for decades

> What matters in the marketplace is the economic reality, the costs of the entire economic process, not who owns what.

In the early 1930s, London based department store Marks & Spencer copied Sears with the same result Twenty years later the Japanese, led by Toyota studied and copied both Sears and Marks & Spencer Then in the 1980s, Wal Mart Stores adapted the approach by allowing suppliers to stock products directly on store shelves thereby eliminating warehouse inventories and with them nearly one third of the cost of traditional retailing

But those companies are still rare exceptions Although economists have known the importance of costing the entire economic chain since Alfred Marshall wrote about it in the late 1890s most businesspeople still consider it theoretical abstraction Increasingly, however, managing the economic cost chain will become a necessity In their article 'From Lean Production to the Lean Enter

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prise" (HBR March April 1994) James P Womack and Daniel T Jones argue persuasively that executives need to organize and manage not only the cost chain but also everything else – especially corporate strategy and product planning – as one economic whole regardless of the legal boundaries of individual companies

A powerful force driving companies toward economic chain costing will be the shift from cost led pricing to price led costing Traditionally, Western companies have started with costs, put a desired profit margin on top, and arrived at a price They practiced cost-led pricing Sears and Marks & Spencer long ago switched to price led costing, in which the price the customer is willing to pay determines allowable costs, beginning with the design stage Until recently, those companies were the exceptions Now price led costing is becoming the rule The Japanese first adopted it for their exports Now Wal Mart and all the discounters in the United States Japan, and Europe are practicing price led costing It underlies Chrysler's success with its recent models and the success of GM's Saturn Companies can practice price led costing, however, only if they know and manage the *entire* cost of the economic chain

When Sears switched to price-led costing, it was the exception. Now it's the rule.

The same ideas apply to outsourcing, alliances, and joint ventures – indeed to any business structure that is built on partnership rather than control And such entities rather than the traditional model of a parent company with wholly owned subsidiaries, are increasingly becoming the models for growth, especially in the global economy

Still it will be painful for most businesses to switch to economic chain costing Doing so requires uniform or at least compatible accounting systems at companies along the entire chain Yet each one does its accounting in its own way, and each is convinced that its system is the only possible one Moreover, economic chain costing requires information sharing across companies, and even within the same company, people tend to resist information sharing Despite those challenges, companies can find ways to practice economic-chain costing now as Procter & Gamble is demonstrating Using the way Wal Mart develops close relationships with suppliers as a model, P&G is initiating information sharing and economic-chain management with the 300 large retailers that distribute the bulk of its products worldwide

Whatever the obstacles, economic chain costing is going to be done Otherwise, even the most efficient company will suffer from an increasing cost disadvantage

Information for Wealth Creation

Enterprises are paid to create wealth, not control costs But that obvious fact is not reflected in traditional measurements First-year accounting students are taught that the balance sheet portrays the liquidation value of the enterprise and provides creditors with worst-case information But enterprises are not normally run to be liquidated They have to be managed as going concerns, that is, for *wealth creation* To do that requires information that enables executives to make informed judgments It requires four sets of diagnostic tools foundation information, productivity information, competence information, and information about the allocation of scarce resources Together, they constitute the executive's tool kit for managing the current business

Foundation Information The oldest and most widely used set of diagnostic management tools are cash-flow and liquidity projections and such standard measurements as the ratio between dealers' inventories and sales of new cars, the earnings coverage for the interest payments on a bond issue and the ratios between receivables outstanding more than six months total receivables, and sales Those may be likened to the measurements a doctor takes at a routine physical weight pulse, temperature, blood pressure and urine analysis If those readings are normal they do not tell us much If they are abnormal they indicate a problem that needs to be identified and treated Those measurements might be called foundation information

Productivity Information The second set of tools for business diagnosis deals with the productivity of key resources The oldest of them – of World War II vintage – measures the productivity of manual labor Now we are slowly developing measurements, though still quite primitive ones, for the productivity of knowledge based and service work However measuring only the productivity of workers, whether blue or white collar, no longer gives us adequate information about productivity We need data on *total factor productivity*

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That explains the growing popularity of economic value added analysis EVA is based on something we have known for a long time what we generally call profits, the money left to service equity, is usually not profit at all Until a business returns a profit that is greater than its cost of capital, it operates at a loss Never mind that it pays taxes as if it had a genuine profit The enterprise still returns less to the economy than it devours in resources It does not cover its full costs unless the reported profit exceeds the cost of capital Until then, it does not create wealth, it destroys it By that measurement, incidentally, few U S businesses have been profitable since World War II

By measuring the value added over *all* costs, including the cost of capital EVA measures, in effect, the productivity of *all* factors of production It does not, by itself, tell us why a certain product or a certain service does not add value or what to do about it But it shows us what we need to find out and whether we need to take remedial action EVA should also be used to find out what works It does show which product, service, operation, or activity has unusually high productivity and adds unusually high value Then we should ask ourselves, What can we learn from those successes?

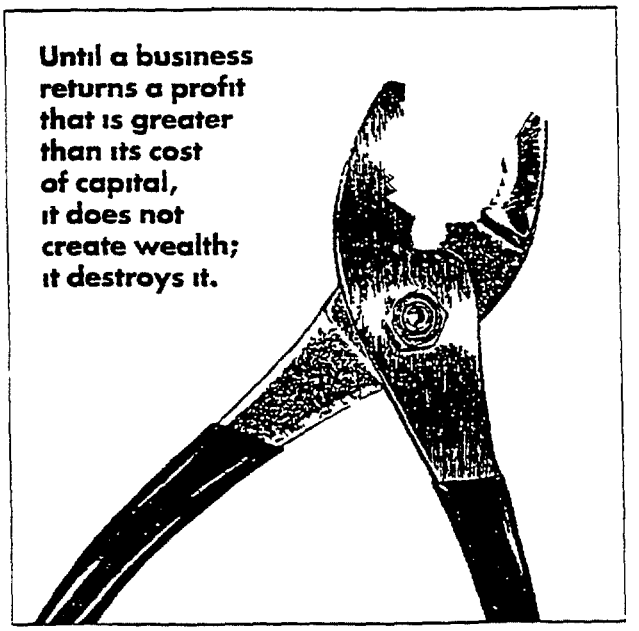
The most recent of the tools used to obtain productivity information is benchmarking–comparing one's performance with the best performance in the industry or, better yet, with the best anywhere in business Benchmarking assumes correctly that what one organization does, any other organization can do as well And it assumes also correctly, that being at least as good as the leader is a prerequisite to being competitive Together, EVA and benchmarking provide the diagnostic tools to measure total factor productivity and to manage it

Competence Information A third set of tools deals with competencies Ever since C K Prahalad and Gary Hamel's pathbreaking article The Core Competence of the Corporation" (HBR May June 1990) we have known that leadership rests on being able to do something others cannot do at all or find difficult to do even poorly It rests on core competencies that meld market or customer value with a special ability of the producer or supplier

Some examples the ability of the Japanese to miniaturize electronic components, which is based on their 300-year old artistic tradition of putting landscape paintings on a tiny lacquer box called an *inro* and of carving a whole zoo of animals on the even tinier button that holds the box on the wearer's belt, called a *netsuke* or the almost unique ability GM has had for 80 years to make successful acquisitions, or Marks & Spencer's also unique ability to design packaged and ready-to eat luxury meals for middle class budgets But how does one identify both the core competencies one has already and those the business needs in order to take and maintain a leadership position? How does one find out whether one's core competence is improving or weakening? Or whether it is still the right core competence and what changes it might need?

So far the discussion of core competencies has been largely anecdotal But a number of highly specialized midsize companies–a Swedish pharmaceutical producer and a U S producer of specialty tools, to name two – are developing the methodology to measure and manage core competencies The first step is to keep careful track of one's own and one's competitors' performances, looking especially for unexpected successes and unexpected poor performance in areas where one should have done well The successes demonstrate what the market values and will pay for They indicate where the business enjoys a leadership advantage The nonsuccesses should be viewed as the first indication either that the market is changing or that the company's competencies are weakening

Until a business returns a profit that is greater than its cost of capital, it does not create wealth; it destroys it.



That analysis allows for the early recognition of opportunities For example, by carefully tracking an unexpected success, a U S toolmaker found that small Japanese machine shops were buying its high-tech, high-priced tools, even though it had not designed the tools with them in mind or made sales calls to them That allowed the company to recog

I discussed EVA at considerable length in my 1964 book *Managing for Results* but the last generation of classical economists Alfred Marshall in England and Eugen Bohm Bawerk in Austria were already discussing it in the late 1890s

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nize a new core competence the Japanese were attracted to its products because they were easy to maintain and repair despite their technical complexity When that insight was applied to designing products the company gained leadership in the small plant and machine shop markets in the United States and Western Europe, huge markets where it had done practically no business before

Core competencies are different for every organization, they are, so to speak, part of an organization's personality But every organization – not just businesses – needs one core competence *innovation* And every organization needs a way to record and appraise its *innovative performance* In organizations already doing that – among them several topflight pharmaceutical manufacturers – the starting point is not the company's own performance It is a careful record of the innovations in the entire field during a given period Which of them were truly successful How many of them were ours Is our performance commensurate with our objectives With the direction of the market With our market standing? With our research spending Are our successful innovations in the areas of greatest growth and opportunity? How many of the truly important innovation opportunities did we miss? Why? Because we did not see them Or because we saw them but dismissed them Or because we botched them? And how well do we convert an innovation into a commercial product A good deal of that admittedly, is assessment rather than measurement It raises rather than answers questions, but it raises the right questions

Resource-Allocation Information The last area in which diagnostic information is needed to manage the current business for wealth creation is the allocation of scarce resources capital and performing people Those two convert into action whatever information management has about its business They determine whether the enterprise will do well or do poorly

GM developed the first systematic capital-appropriations process about 70 years ago Today practically every business has a capital appropriations process, but few use it correctly Companies typically measure their proposed capital appropriations by only one or two of the following yardsticks return on investment payback period, cash flow or discounted present value But we have known for a long time – since the early 1930s – that none of those is *the* right method To understand a proposed investment a company needs to look at *all* four Sixty years ago, that would have required endless number crunching Now a laptop computer can provide the information within a few minutes We also have known for 60 years that managers should never look at just one proposed capital appropriation in isolation but should instead choose the projects that show the best ratio between opportunity and risks That requires a capital-appropriations *budget* to display the choices – again, something far too many businesses do not do Most serious, however is that most capital appropriations processes do not even ask for two vital pieces of information

- What will happen if the proposed investment fails to produce the promised results as do three out of every five Would it seriously hurt the company, or would it be just a flea bite
- If the investment is successful – and especially if it is more successful than we expect – what will it commit us to? No one at GM seems to have asked what Saturn's success would commit the company to As a result, the company may end up killing its own success because of its inability to finance it

In addition a capital-appropriations request requires specific deadlines When should we expect what results? Then the results – successes, near successes, near failures, and failures – need to be reported and analyzed There is no better way to improve an organization's performance than to measure the results of capital appropriations against the promises and expectations that led to their authorization How much better off the United States would be today had such feedback on government programs been standard practice for the past 50 years

Capital, however, is only one key resource of the organization, and it is by no means the scarcest one The scarcest resources in any organization are performing people Since World War II, the U S military – and so far no one else – has learned to test

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its placement decisions It now thinks through what it expects of senior officers before it puts them into key commands It then appraises their performance against those expectations And it constantly appraises its own process for selecting senior commanders against the successes and failures of its appointments In business by contrast placement with specific expectations as to what the appointee should achieve and systematic appraisal of the outcome are virtually unknown In the effort to create wealth, managers need to allocate human resources as purposefully and as thoughtfully as they do capital And the outcomes of those decisions ought to be recorded and studied as carefully

Where the Results Are

Those four kinds of information tell us only about the current business They inform and direct *tactics* For *strategy* we need organized information about the environment Strategy has to be based on information about markets customers and noncustomers, about technology in one s own industry and others, about worldwide finance, and about the changing world economy For that is where the results are Inside an organization, there are only cost centers The only profit center is a customer whose check has not bounced

Major changes also start outside an organization A retailer may know a great deal about the people who shop at its stores But no matter how successful it is, no retailer ever has more than a small fraction of the market as its customers the great majority are noncustomers It is always with noncustomers that basic changes begin and become significant

At least half the important new technologies that have transformed an industry in the past 50 years came from outside the industry itself Commercial paper, which has revolutionized finance in the United States did not originate with the banks Molecular biology and genetic engineering were not developed by the pharmaceutical industry Though the great majority of businesses will continue to operate only locally or regionally, they all face at least potentially global competition from places they have never even heard of before

Not all of the needed information about the outside is available, to be sure There is no information – not even unreliable information – on economic conditions in most of China for instance, or on legal conditions in most of the successor states to the Soviet empire But even where information is readily available many businesses are oblivious to it Many U S companies went into Europe in the 1960s without even asking about labor legislation European companies have been just as blind and ill informed in their ventures into the United States A major cause of the Japanese real estate investment debacle in California during the 1990s was the failure to find out elementary facts about zoning and taxes

A serious cause of business failure is the common assumption that conditions – taxes social legislation market preferences distribution channels intellectual property rights and many others – *must* be what we think they are or at least what we think they *should* be An adequate information system has to include information that makes executives question that assumption It must lead them to ask the right questions not just feed them the information they expect That presupposes first that executives know what information they need It demands further that they obtain that information on a regular basis It finally requires that they systematically integrate the information into their decision making

> Inside an organization, there are only cost centers. The only profit center is a customer whose check has not bounced.

A few multinationals – Unilever Coca Cola Nestle the big Japanese trading companies and a few big construction companies – have been working hard on building systems to gather and organize outside information But in general the majority of enterprises have yet to start the job

Even big companies in large part will have to hire outsiders to help them To think through what the business needs requires somebody who knows and understands the highly specialized information field There is far too much information for any but specialists to find their way around The sources are totally diverse Companies can generate some of the information themselves such as information about customers and noncustomers or about the technology in one s own field But most of what enterprises need to know about the environment is obtainable only from outside sources – from all kinds of data banks and data services, from journals

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in many languages, from trade associations, from government publications from World Bank reports and scientific papers and from specialized studies

Another reason there is need for outside help is that the information has to be organized so it questions and challenges a company's strategy To supply data is not enough The data have to be integrated with strategy, they have to test a company's assumptions and they must challenge a company's current outlook One way to do that may be a new kind of software information tailored to a specific group – say, to hospitals or to casualty insurance companies The Lexis database supplies such information to lawyers but it only gives answers it does not ask questions What we need are services that make specific suggestions about how to use the information, ask specific questions regarding the users' business and practices and perhaps provide interactive consultation Or we might "outsource" the outside information system Maybe the most popular provider of the outside information system especially for smaller enterprises will be that inside outsider the independent consultant

Whichever way we satisfy it the need for information on the environment where the major threats and opportunities are likely to arise will become increasingly urgent

It may be argued that few of those information needs are new and that is largely true Conceptually many of the new measurements have been discussed for many years and in many places What is new is the technical data processing ability It enables us to do quickly and cheaply what only a few short years ago would have been laborious and very expensive Seventy years ago, the time-and-motion study made traditional cost accounting possible Computers have now made activity based cost accounting possible, without them, it would be practically impossible

But that argument misses the point What is important is not the tools It is the concepts behind them They convert what were always seen as discrete techniques to be used in isolation and for separate purposes into one integrated information system That system then makes possible business diagnosis, business strategy, and business decisions That is a new and radically different view of the meaning and purpose of information as a measurement on which to base future action rather than as a postmortem and a record of what has already happened

The command and control organization that first emerged in the 1870s might be compared to an organism held together by its shell The corporation that is now emerging is being designed around a skeleton *information* both the corporation's new integrating system and its articulation

Our traditional mind set–even if we use sophisticated mathematical techniques and impenetrable sociological jargon–has always somehow perceived business as buying cheap and selling dear The new approach defines a business as the organization that adds value and creates wealth

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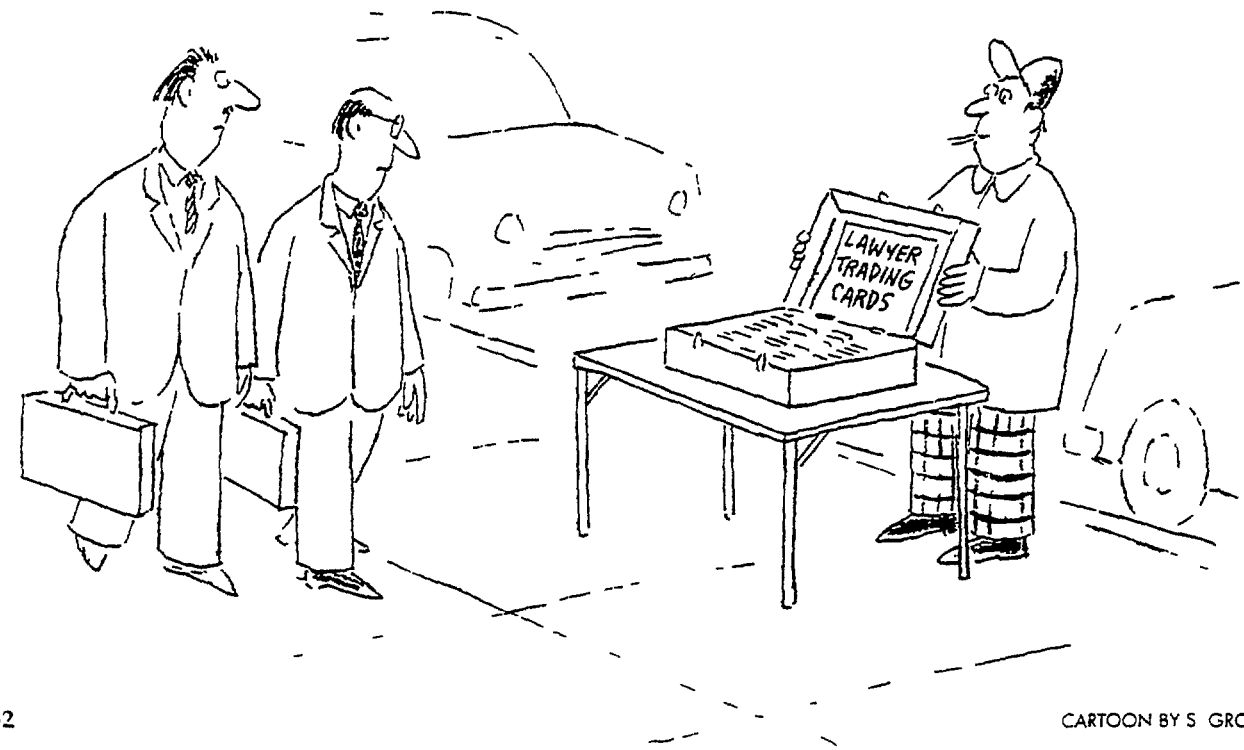

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Use activity-based costing to guide corporate strategy

Measure Costs Right: Make the Right Decisions

by Robin Cooper and Robert S Kaplan

Managers in companies selling multiple products are making important decisions about pricing, product mix and process technology based on distorted cost information What s worse alternative information rarely exists to alert these managers that product costs are badly flawed Most companies detect the problem only after their competitiveness and profitability have deteriorated

Distorted cost information is the result of sensible accounting choices made decades ago when most companies manufactured a narrow range of products Back then, the costs of direct labor and materials, the most important production factors could be traced easily to individual products Distortions from allocating factory and corporate overhead by burden rates on direct labor were minor And the expense of collecting and processing data made it hard to justify more sophisticated allocation of these and other indirect costs

Today, product lines and marketing channels have proliferated Direct labor now represents a small fraction of corporate costs while expenses covering factory support operations marketing, distribution engineering, and other overhead functions have exploded But most companies still allocate these rising overhead and support costs by their diminishing direct labor base or as with marketing and distribution costs not at all

These simplistic approaches are no longer justifiable – especially given the plummeting costs of information technology They can also be dangerous Intensified global competition and radically new production technologies have made accurate product cost information crucial to competitive success

Bad information on product costs leads to bad competitive strategy

We have written extensively on the shortcomings of typical cost accounting systems [1] In this article we present an alternative approach which we refer to as activity based costing The theory behind our method is simple Virtually all of a company s activities exist to support the production and delivery of today s goods and services They should therefore all be considered product costs And since nearly all fac

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tory and corporate support costs are divisible or separable they can be split apart and traced to individual products or product families These costs include

Logistics
Production
Marketing and Sales
Distribution
Service
Technology
Financial Administration
Information Resources
General Administration

Conventional economics and management accounting treat costs as variable only if they change with short-term fluctuations in output We (and others) have found that many important cost categories vary not with short term changes in output but with changes over a period of years in the design mix, and range of a company's products and customers An effective system to measure product costs must identify and assign to products these costs of complexity

Many managers understand intuitively that their accounting systems distort product costs, so they make informal adjustments to compensate But few can predict the magnitude and impact of the adjustments they should be making

Consider the experience of a leading manufacturer of hydraulic valves whose product line included thousands of items About 20% of the valves generated 80% of total revenues a typical ratio for multiproduct organizations Of even greater interest 60% of the products generated 99% of the revenues Nonetheless management remained enthusiastic about the 40% of its products that generated only 1% of revenues According to its cost system these specialty items had the best gross margins

An analysis using activity based costing told a very different story More than 75% of this company's products (mostly the low-volume items) were *losing* money The products that did make money (fewer than one in four) generated more than 80% of sales and 300% of net profits

Top executives may be understandably reluctant to abandon existing product cost systems in favor of a new approach that reflects a radically different philosophy We do not advocate such an abrupt overhaul The availability of cheap, powerful personal computers spread sheets, and data base languages allows businesses to develop new cost systems for strategic purposes off-line from official accounting systems Companies don t have to commit their entire accounting system to activity based costing to use it

Indeed activity based costing is as much a tool of corporate strategy as it is a formal accounting system Decisions about pricing, marketing, product design, and mix are among the most important ones managers make None of them can be made effectively without accurate knowledge of product costs

What Distorts Cost Data?

Product cost distortions occur in virtually all organizations producing and selling multiple products or services To understand why, consider two hypothetical plants turning out a simple product, ball point pens The factories are the same size and have the same capital equipment Every year Plant I makes one million blue pens Plant II also produces blue pens but only 100,000 per year To fill the plant, keep the work force busy, and absorb fixed costs, Plant II also produces a variety of similar products 60,000 black pens, 12,000 red pens, 10,000 lavender pens, and so on In a typical year, Plant II produces up to 1,000 product variations with volumes ranging between 500 and 100,000 units Its aggregate annual output equals the one million units of Plant I, and it requires the same total standard direct labor hours machine hours and direct material

Despite the similarities in product and total output a visitor walking through the two plants would notice dramatic differences Plant II would have a much larger production support staff—more people to schedule machines, perform setups, inspect items after setup, receive and inspect incoming materials and parts move inventory, assemble and ship orders expedite orders rework defective items, design and implement engineering change orders, negotiate with vendors schedule materials and parts receipts and update and program the much larger computer based information system Plant II would also operate with considerably higher levels of idle time overtime inventory, rework and scrap

Plant II's extensive factory support resources and production inefficiencies generate cost-system distortions Most companies allocate factory support costs in a two-step process First, they collect the costs into categories that correspond to responsibility centers (production control quality assurance, receiving) and assign these costs to operating departments Many companies do this first step very well

But the second step—tracing costs from the operating departments to specific products—is done sim

1 See Robert S Kaplan and H Thomas Johnson *Relevance Lost The Rise and Fall of Management Accounting* (Boston Harvard Business School Press 1987) and Robin Cooper and Robert S Kaplan How Cost Accounting Distorts Product Costs *Management Accounting* April 1988 p 20

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plistically Many companies still use direct labor hours as an allocation base Others, recognizing the declining role of direct labor use two additional allocation bases Materials related expenses (costs to purchase, receive inspect and store materials) are allocated directly to products as a percentage markup over direct materials costs And machine hours, or processing time are used to allocate production costs in highly automated environments

Whether Plant II uses one or all of these approaches, its cost system invariably—and mistakenly—reports production costs for the high volume product (blue pens) that greatly exceed the costs for the same product built in Plant I One does not need to know much about the cost system or the production process in Plant II to predict that blue pens which represent 10% of output will have about 10% of the factory costs allocated to them Similarly, lavender pens, which represent 1% of Plant II's output, will have about 1% of the factory's costs allocated to them In fact, if the standard output per unit of direct labor hours, machine hours and materials quantities are the same for blue pens as for lavender pens, the two types of pens will have *identical* reported costs

> Existing cost systems frequently understate profits on high-volume products and overstate profits on specialty items

—even though lavender pens which are ordered, fabricated, packaged, and shipped in much lower volumes, consume far more overhead per unit

Think of the strategic consequences Over time, the market price for blue pens, as for most high volume products, will be determined by focused and efficient producers like Plant I Managers of Plant II will notice that their profit margin on blue pens is lower than on their specialty products The price for blue pens is lower than for lavender pens but the cost system reports that blue pens are as expensive to make as the lavender

While disappointed with the low margins on blue pens Plant II's managers are pleased they're a full-line producer Customers are willing to pay premiums for specialty products like lavender pens, which are apparently no more expensive to make than commodity-type blue pens The logical strategic response? De emphasize blue pens and offer an expanded line of differentiated products with unique features and options

In reality, of course, this strategy will be disastrous Blue pens in Plant II are cheaper to make than lavender pens—no matter what the cost system reports Scaling back on blue pens and replacing the lost output by adding new models will further increase overhead Plant II's managers will simmer with frustration as total costs rise and profitability goals remain elusive An activity based cost system would not generate distorted information and misguided strategic signals of this sort

Designing an Activity-Based Cost System

The first step in designing a new product cost system is to collect accurate data on direct labor and materials costs Next examine the demands made by particular products on indirect resources Three rules should guide this process

1 Focus on expensive resources

2 Emphasize resources whose consumption varies significantly by product and product type, look for diversity

3 Focus on resources whose demand patterns are uncorrelated with traditional allocation measures like direct labor, processing time, and materials

Rule 1 leads us to resource categories where the new costing process has the potential to make big differences in product costs A company that makes industrial goods with a high ratio of factory costs to total costs will want a system that emphasizes tracing manufacturing overhead to products A consumer goods producer will want to analyze its marketing, distribution, and service costs by product lines, channels, customers, and regions High technology companies must study the demands made on engineering, product improvement, and process development resources by their different products and product lines

Rules 2 and 3 identify resources with the greatest potential for distortion under traditional systems They point to activities for which the usual surrogates—labor hours material quantities or machine hours—do not represent adequate measures of resource consumption The central question is, which parts of the organization tend to grow as the company increases the diversity of its product line its processing technologies its customer base, its marketing channels, its supplier base?

The process of tracing costs, first from resources to activities and then from activities to specific products cannot be done with surgical precision We cannot estimate to four significant digits the added

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Allocating Cost[illegible] nder an Activi[illegible]-Based System

The process of designing and implementing an activity basec[illegible] system for support departments usually beg[illegible] interviews of the department heads The [illegible]ews yield insights into depart mental ope[illegible] and into the factors that trigger department[illegible] activities Subsequent analysis traces these activities to specific products

The following example illustrates the activity based costing process for an inventory control department responsible for raw materials and purchased components The annual costs associated with the departm[illegible]t (mainly personnel costs) are $500,[illegible]0

Interview Department H[illegible]

Q How many people work for you?

A Twelve

Q What do they do?

A Six of them spend most of their time handling incom[illegible] shipments of purchased parts They han dle eve[illegible]ning—from documentation to transfer ring parts to the WIP stockroom Three others work in raw materials After the material clears inspec tion, they move it into inventory and take care of the paperwork

Q What determines the time required to process an incoming shipment? Does it matter if the shipment is large or small?

A Not for parts They go directly to the WIP stockroom and unless it's an extremely large shipment it can be handled in one trip With raw materials though volume can play a big role in processing time But there are only a few large raw material shipments Over the course of a year the time re quired to process a part or raw material really depends on the number of times it's received, not on the size of the shipments in which it comes

Q What other factors affect your department's work load?

A Well, there are three people I haven't discussed yet They disburse raw material to the shop floor Again volume is not really an issue it's more the number of times material has to be disbursed

Q Do you usually disburse the total amount of ma terial required for a production run all at once or does it go out in smaller quantities?

A It varies with the size of the run On a big run we can't disburse it all at once—there would be too much raw material on the shop floor On smaller runs—and I'd say that's 80% of all runs—we'd send it there in a single trip once setup is complete

Design the System

After the interview, the system designer can use the number of people involved in each activity to al locate the department's $500,000 cost

Act[illegible]y	P[illegible]ple	Total Cost
Rec[illegible]ing purchased parts	6	**$250,000**
Receiving raw material	3	**$125,000**
Disbursing material	3	**$125,000**

In 1987, this company received 25,000 shipments of purchased parts and 10 000 shipments of raw materials The factory made 5,000 production runs Dividing these totals into the support dollars associated with each activity yields the followir costs per unit of activity

Activity	Allocation Measure	Unit Cost
Receiving purchased parts	**Number of shipments per year**	**$10 per shipment**
Receiving raw material	**Number of shipments per year**	**$12.50 per shipment**
Disbursing material	**Number of production runs**	**$25 per run**

We can now attribute inventory control support costs to specific products Suppose the company manufactures 1 000 units of Product A in a year. Product A is a complex product with more than 50 purchased parts and several different types of raw material During the year the 1 000 units were assembled in 10 different production runs requiring 200 purchased parts shipments and 50 different raw material shipments Product A incurs $2,875 in in ventory control overhead ($10 × 200 + $12 50 × 50 + $25 × 10) to produce the 1,000 units or $2 88 of inventory control costs per unit

Product A also consumed 1 000 hours of direct la bor out of the factory's total of 400,000 hours A labor based allocation system would allocate $1,250 of inventory control costs to the 1 000 units produced ($500 000/400,000 × 1 000) for a per unit cost of $1 25 The 230% cost difference between the activity based attribution ($2 88) and the labor-based allocation ($1 25) reflects the fact that the complex low-volume Product A demands a much greater share of inventory control resources than its share of factory direct labor hours

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burden on support resources of introducing two new variations of a product But it is better to be basically correct with activity based costing, say, within 5% or 10% of the actual demands a product makes on organizational resources than to be precisely wrong (perhaps by as much as 200%) using outdated allocation techniques

The insert "Allocating Costs under an Activity Based System" shows how a company might calculate and assign the support costs of a common manufacturing overhead function—raw materials and parts control The principles and methods, while illustrated in a conventional manufacturing setting, are applicable to any significant collection of corporate resources in the manufacturing or service sector

The Impact of Activity-Based Costing

An activity based system can paint a picture of product costs radically different from data generated by traditional systems These differences arise because of the system's more sophisticated approach to attributing factory overhead, corporate overhead, and other organizational resources, first to activities and then to the products that create demand for these indirect resources

Manufacturing Overhead Let's look more closely at the manufacturer of hydraulic valves mentioned earlier Cost information on seven representative products is presented in the table How Activity Based Costing Changes Product Profitability" Under the old cost system the overhead charge per unit did not differ much among the seven valves ranging from $5 34 to $8 88 Under the new system, which traces overhead costs directly to factory support activities and then to products, the range in overhead cost per unit widened dramatically—from $4 39 to $77 64 With four low to medium volume products (valves 2 through 5) the overhead cost estimate increased by 100% or more For the two highest volume products (valves 1 and 6) the overhead cost declined

The strategic consequences of these data are enormous Under the labor based cost system valve 3 was considered the most profitable product of the seven with a gross margin of 47% The activity based system in contrast revealed that when orders for valve 3 arrived the company would have done better to mail its customers cash to buy the valves elsewhere than to make them itself

Labor based cost systems don't always underestimate the overhead demands of low volume products Valve 7 with the second lowest volume in the group, shows a marked decrease in overhead under an activity based system Why? Valve 7 is assembled from components already being used on the high-volume products (valves 1 and 6) The bulk of any factory's overhead costs are associated with ordering parts, keeping track of them inspecting them, and setting up to produce components For parts and components ordered or fabricated in large volumes, the per unit impact of these transaction costs is modest Therefore, specialized products assembled from high volume components will have low production costs even if shipping volume is not high

Marketing Expenses The redesign of cost systems should not be limited to factory support costs Many companies have selling, general, and administrative (SG&A) expenses that exceed 20% of total revenues Yet they treat these costs as period expenses, not charges to be allocated to products While such "below the [gross margin] line" treatment may be adequate even required, for financial accounting, it is poor practice for measuring product costs

We studied a building supplies company that distributed its products through six channels—two in the consumer market and four in the commercial market Across all its products, this company had an average gross margin of 34% Marketing costs for the six channels averaged 16 4% of sales, with general and administrative expenses another 8 5% (The tables entitled "OEM Changes from a Laggard to a Solid Performer" present information on the four commercial channels)

With operating profits in the commercial sector at only about 10% of revenues the company was looking to improve its profitability Management decided to focus on SG&A expenses Previously, the company had allocated SG&A costs by assigning 25% of sales—the company average—to each distribution segment A more sophisticated analysis, similar in philosophy to the overhead analysis performed by the hydraulic valve company, produced striking changes in product costs

> Management thought valve 3 was a cash cow It might as well have mailed checks to its customers

The OEM business was originally a prime target for elimination Its 27% gross margin and laggard 2% operating margin put it at the bottom of the pack among commercial channels But the OEM channel

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How Activity-Based Costing Changes Product Profitability*

Valve Number	Annual Volume (units)	Manufacturing Overhead Per Unit: Old System	New System	Percent Difference	Gross Margin: Old System	New System
1	4,562	$5 44	$ 4 76	− 12 5%	41%	46%
2	500	6 15	12 86	+109 0	30	− 24
3	53	7 30	77 64	+964 0	47	−258
4	2,079	8 88	19 76	+123 0	26	− 32
5	5,670	7 58	15 17	+100 0	39	2
	11,196	5 34	5 26	− 1 5	41	41
	423	5 92	4 39	− 26 0	31	43

* are not confident that the table s figures are exactly correct For example, students of this case have estimated the appropriate overhead charge on valve 3 (listed at $77 64 per unit) to be as low as $64 and as high as $84 Whatever the exact figure the difference between this activity based cost and the original estimate ($7 30 per unit) suggests that the current labor based system is seriously flawed.

u virtually no resources in several major selling c nes advertising, catalog, sales promotion, and w nty In the remaining selling categories, the OE hannel used proportionately fewer resources per s es dollar than the other major channels Its marketing expenses were 9% of sales well below the 15% average for the four commercial channels A sounder estimate of OEM operating margin was 9% not 2%

e OEM segment looked even better after the c nv extended the analysis by allocating in- v capital to specific channels The OEM busi- n quired far less investment in working capital—accounts receivable and inventory—than the other commercial channels Thus even though the OEM channel had a below-average gross margin its bottom line return on investment turned out to be r than the commercial average

her Corporate Overhead Virtually all organiza- al costs, not just factory overhead or marketing expenses, can and should be traced to the activities for which these resources are used, and then to the divisions, ch els and product lines that consume them W aeuser Company recently tituted a charge system to trace corporate overhead departm osts to the activities that drive them

For example, Weyerhaeuser's financial services department analyzed all the activities it performed—including data base administration general account ing, accounts payable and receivable and inv ing—to determine what factors create dema for them A division dealing with a small num r of high volume customers makes very different demands on activities like accounts receivable from a division with many low-volume customers Before instituting the charge-back system, Weyerhaeuser applied the cost of accounts receivable and other functions as a uniform percentage of a division's sales—a driver that bore little or no relation to the activities that created the administrative work Now it allocates costs based on which divisions (and product lines) generate the costs

Similarly, companies engaged in major product development and process improvements should attribute the costs of design and engineering resources to the products and product lines that benefit from them Otherwise product and process modification costs will be shifted onto product lines for which little development effort is being performed

Where Does Activity-Based Costing Stop?

We believe that only two types of cos should be excluded from a system of activity-b d costing First, the costs of excess capacity should not be charged to individual products To use a simplified example consider a one product plant whose practical production capacity is one million units per year The plant's total annual costs amount to $5 million At full capacity the cost per unit is $5 This is the unit product cost the company should use regardless of the plant s budgeted production volume The cost of excess or idle capacity should be treated as a separate line item—a cost of the period, not of individual products

* See H Thomas Johnson and Dennis A Loewe How Weyerhaeuser Manages Corporate Overhead Costs *Management Accounting* August 1987 p 20

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OEM Changes from a Laggard .

Profits by Commercial Distribution Channel (Old System)

	Contract	Industrial Suppliers	Government	OEM	Total Commercial
Annual Sales *(in thousands of dollars)*	$79 434	$25 110	$422	$9 200	$114 166
Gross Margin	34%	41%	23%	27%	35%
Gross Profit	$27 375	$10,284	$136	$2,461	$ 40,256
SG&A Allowance* *(in thousands of dollars)*	$19 746	$ 6 242	$105	$2 287	$ 31,814
Operating Profit *(in thousands of dollars)*	$ 7,629	$ 4 042	$ 31	$ 174	$ 11 876
Operating Margin	10%	16%	7%	2%	10%
Invested Capital Allowance† *(in thousands of dollars)*	$33 609	$10 624	$179	$3,893	$ 48 305
Return on Investment	23%	38%	17%	4%	25%

*SG&A allowance for each channel is 25% of that channel s revenues
†Invested capital allowance for each channel is 42% of that channel s revenues

Many companies however, spread capacity costs over budgeted volume Returning to our example, if demand exists for only 500,000 units, a traditional cost system will report that each unit cost $10 to build ($5 million/500 000) even though workers and machines have become no less efficient in terms of what they could produce Such a procedure causes product costs to fluctuate erratically with changes in assumed production volume and can lead to the "death spiral" A downturn in forecast demand creates idle capacity The cost system reports higher costs So management raises prices which guarantees even less demand in the future and still higher idle capacity costs

The second exclusion from an activity based cost system is research and development for entirely new products and lines We recommend splitting R&D costs into two categories those that relate to improvements and modifications of existing products and lines and those that relate to entirely new products The first category can and should be traced to the products that will benefit from the development effort Otherwise the costs will be spread to products and lines that bear no relationship to the applied R&D program

The second category is a different animal Financial accounting treats R&D as a cost of the period in which it takes place The management accounting system in contrast should treat these costs as investments in the future Companies engaged in extensive R&D for products with short life cycles should measure costs and revenues over the life cycle of their products Any periodic assessment of product profitability will be misleading, since it depends on the arbitrary amortization of investment expenditures including R&D

Strategic Implications

The examples we've discussed demonstrate how an activity-based cost system can lead to radically different evaluations of product costs and profitability than more simplistic approaches It does not imply that because some low-volume products (lavender pens or valve 3) now are unprofitable, a company should immediately drop them Many customers value having a single source of supply, a big reason companies become full line producers It may be impossible to cherry pick a line and build only profitable products If the multiproduct pen company wants to sell its profitable blue and black pens, it may have to absorb the costs of filling the occasional order for lavender pens

Once executives are armed with more reliable cost information, they can ponder a range of strategic options Dropping unprofitable products is one So is raising prices perhaps drastically Many low-volume products have surprisingly low price elasticities Customers who want lavender pens or valve 3 may be willing to pay much more than the current price On the other hand, these customers may also react to a price increase by switching away from low-volume products That too is acceptable, the company would be supplying fewer money losing items

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..to a Solid Performer

Profits by Commercial Distribution Channel (New System)

	Contract	Industrial Suppliers	Government	OEM	Total Commercial
Gross Profit *(from previous table)*	$27 375	$10,284	$136	$2 461	$40,256
Selling Expenses* *(all in thousands of dollars)*					
Commission	$ 4 682	$ 1,344	$ 12	$ 372	$ 6,410
Advertising	132	38	0	2	172
Catalog	504	160	0	0	664
Co op Advertising	416	120	0	0	536
Sales Promotion	394	114	0	2	510
Warranty	64	22	0	4	90
Sales Administration	5,696	1,714	20	351	7,781
Cash Discount	892	252	12	114	1,270
Total	$12,780	$ 3,764	$ 44	$ 845	$17,433
G&A *(in thousands of dollars)*	$ 6 740	$ 2,131	$ 36	$ 781	$ 9,688
Operating Profit *(in thousands of dollars)*	$ 7,855	$ 4,389	$ 56	$ 835	$13,135
Operating Margin	10%	17%	13%	9%	12%
Invested Capital*	$33 154	$10,974	$184	$2,748	$47,060
Return on Investment	24%	40%	30%	30%	28%

*Selling expenses and invested capital estimated under an activity based system.

More accurate cost information also raises strategic options for high-volume products Plant II might consider dropping its prices on blue pens The old cost system, which shifted overhead charges onto these high-volume products, created a price umbrella that benefited focused competitors like Plant I Pricing its core product more competitively might help Plant II reverse a market-share slide

Managers in the building supplies company we described took several profit enhancing steps after receiving the revised cost data by distribution channels They began emphasizing the newly attractive OEM segment and any new business where marketing costs would be well below the company average

Information generated by an activity based cost system can also encourage companies to redesign products to use more common parts Managers frequently exhort their engineers to design or modify products so they use fewer parts and are easier to manufacture But these exhortations will ring hollow if the company's cost system cannot identify the benefits to design and manufacturing simplicity Recall valve 7, a low-volume product made from components fabricated in large volumes for other products Now that the company can quantify, using activity based techniques the impressive cost benefits of component standardization, the entire organization will better understand the value of designing products for manufacturability

Likewise, activity-based costing can change how managers evaluate new process technologies Streamlining the manufacturing process to reduce setup times, rationalizing plant layout to lower material handling costs, and improving quality to reduce postproduction inspections can all have major impacts on product costs – impacts that become visible on a product by-product basis with activity-based costing A more accurate understanding of the costs of specialized products may also make computer integrated manufacturing (CIM) look more attractive, since CIM is most efficient in high-variety, low-volume environments

Activity-based costing is not designed to trigger automatic decisions It is designed to provide more accurate information about production and support activities and product costs so that management can focus its attention on the products and processes with the most leverage for increasing profits It helps managers make better decisions about product design, pricing, marketing, and mix, and encourages continual operating improvements

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ENERGY TRAINING PROGRAM

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Volume II

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11 00 - 12 00	External Impacts on a Distribution Company External Suppliers External Influences External Clients Other External Forces	Mr Billy Ussery
12 00 - 1 00	Lunch	
1 00 - 2 45	Establishment of Customer Focused Service Including Metering Billing Collections Customer Needs / Demands	Mr Billy Ussery
2 45 - 3 00	Break	
3 00 - 5 00	Establishment of Customer Focused Service Cont	Mr Billy Ussery

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OVERVIEW

OF

BACKGROUND

Overview of Morning Session

- My Background
- Utility Structure in the US
- External Influences on Utilities

My Background

- Middle Georgia College (1982-85)
- Auburn University (1985-87)
- Sawnee EMC - Systems Engineer (1987-89)
- Sawnee EMC - Manager of Engineering (1989 - Present)

Corporate Overview

- Distribution Cooperative
- 1 of 42 in the State of Georgia
- Over 1000 in the US
- Top 20 Largest in the US
- Top 5 Fastest Growing in US

Corporate Statistics

Item	1987	1996
Operating Revenue	$42,541,781	$106,199,605
Purchased Power Cost	$28,151,288	$72,159,350
Total Operations and Maintenance Expense	$34,279,448	$88,061,568
Total Miles of Line	3294	5800
Miles of Overhead	2563	2922
Miles of Underground	731	2878
Total Services	44,478	77,703

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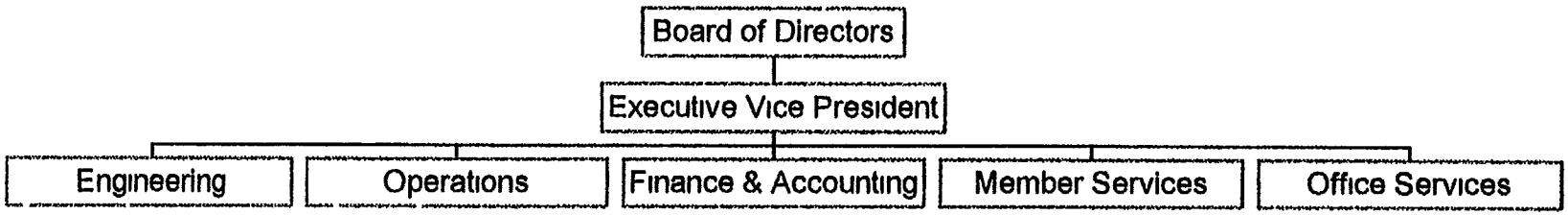
Corporate Statistics

Item	1987	1997
Number of Employees	181	240
Number of Contractors	50	250
Total Liabilities	$74,323,053	$200,619,384
Annual System Peak	164 MW	382 MW

Corporate Structure



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My Responsibilities

- System Planning
- Staking
- Drafting / Mapping
- Warehouse
- Buildings and Grounds
- Contractors

EXTERNAL IMPACTS

ON A

DISTRIBUTION COMPANY

Utility Types in the USA

BASIC UTILITY TYPES

• COOPERATIVE	940
• MUNICIPAL	1810
• INVESTOR OWNED	206
• FEDERAL	37
• STATE	148

UTILITY CHARACTERISTICS

- INVESTOR OWNED
  - Provides 78% of all Power Generated in US
  - Provides Electricity to 75% of Population
  - Owned by Investors
  - Most are fully Integrated with Generation, Transmission and Distribution (but changing)

UTILITY CHARACTERISTICS

- Cooperatives
  - Approximately 1000 in US
  - Mostly Distribution with some Generation
  - Governed by Member Elected Board of Directors
  - Owned by its Members/Consumers

UTILITY CHARACTERISTICS

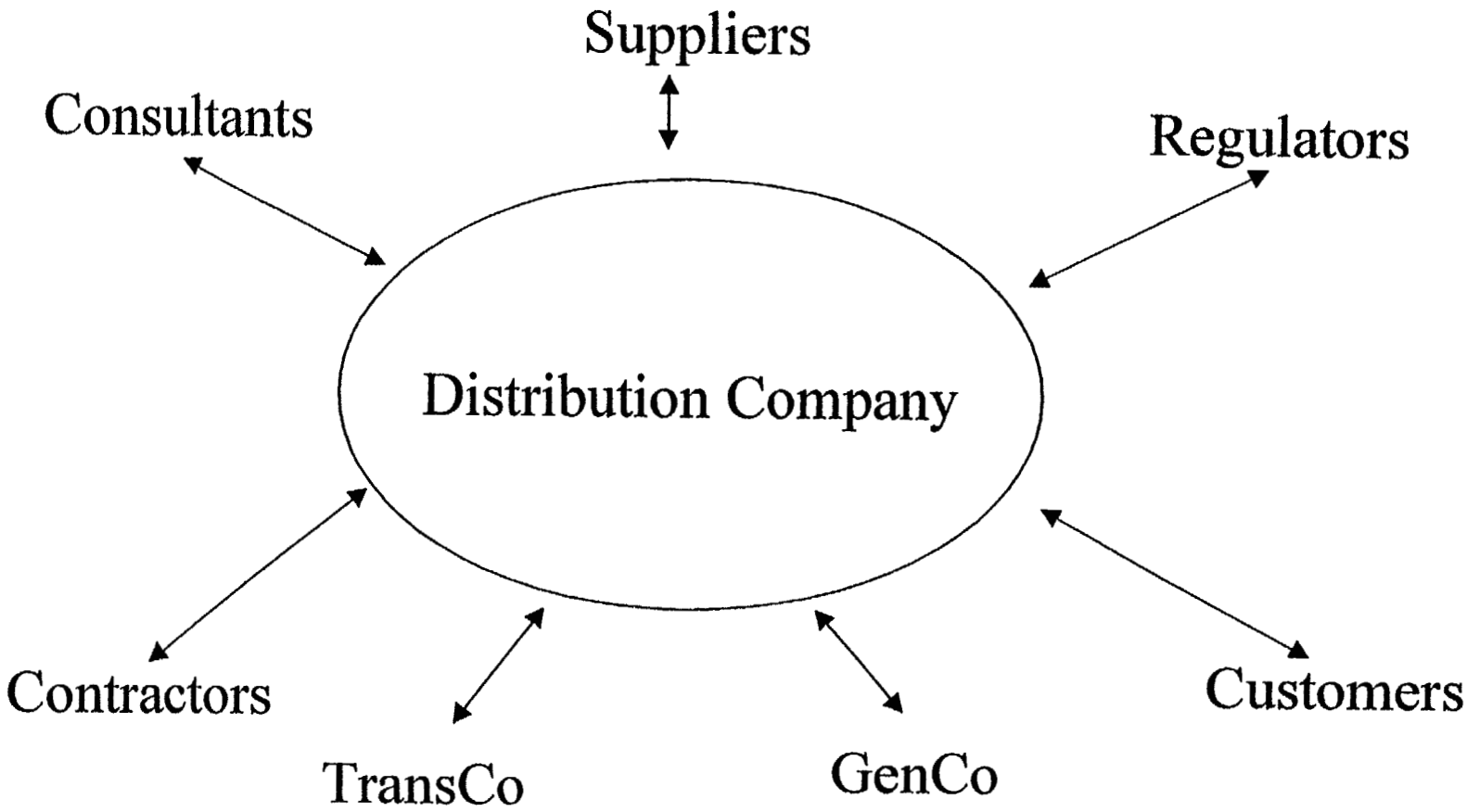
- Municipal Electric Systems
  - Owned by Cities or Other Municipality
  - Self Regulated by City Management
  - Provides 11% of US Electricity Needs

UTILITY CHARACTERISTICS

- Federal Electric Utilities
  - Agencies of the US Federal Government
  - Usually Generation and Transmission Only
  - Army Corp of Engineers - Hydro Projects
  - Tennessee Valley Authority

External Influences on the Distribution Company

External Influences



EXTERNAL INFLUENCES

- Extremely Important
- Excellent Source of Information
- Necessary to Build Relationships
- Critical to Successful Operation

External Influences
Regulators

- Federal Guidelines, Policies and Procedures
- Local or State Guidelines
- Public Service Commission
- Many Other Influences Covered Last Week

External Influences
Suppliers

- Material Management
- Competitive Pricing
- Material Availability During Emergencies
- Support and Technical Assistance for Various Products

External Influences
Consultants

- Knowledge of What Others Are Doing
- Assistance with Problems
- Third Party Oversight and Review
- Potential Support for Seasonal Projects

External Influences
Contractors

- Extremely Important for Natural Disasters
- Additional Help During Peak Construction
- Stabilization of Work Force
- Lower Cost (sometimes)

External Influences
TransCo

- Provider of Transmission Services
  - Transmission Lines
  - Substations
  - Spare Parts Inventory for Substations
- Reliability of Transmission System

External Influences
GenCo

- Provider of Generation Services
- Possible Other Services
  - Planning
  - Modeling
  - Etc……

External Influences
Customers

- Most Important External Influence
- Dictates Many Policies and Procedures
- Very Dynamic Group
- Not All Have the Same Needs and Desires
- Very Diverse Backgrounds

External Influences Summary

- All Important
- Establish a Balance With All Parties
- Each Affects Many Aspects of the Organization
- Each Has Very Different Expectations

55

ESTABLISHMENT OF CUSTOMER

FOCUSED SERVICE

CUSTOMER SERVICE

Customer Focused Service

- CUSTOMER SERVICE
- CUSTOMER SERVICE
- CUSTOMER SERVICE

- ***EXTREMELY IMPORTANT FOR SUCCESSFUL DISTRIBUTION COMPANY***

Customer Service from A……Z

- Attitude
- Billing
- Collections
- Metering
- Service Requests
- Many Many Many More

REMEMBER !!

CUSTOMER SERVICE MEANS
DIFFERENT THINGS TO
DIFFERENT PEOPLE

CUSTOMER SERVICE KEYS
Day to Day Support Services

- New Service Applications
- Deposits
- Disconnects
- Reconnects
- Billing Questions
- Billing Complaints
- Outage Notification
- Metering
- Miscellaneous "*Extra*" Services
- Other Miscellaneous Customer Requests (Many, Many, Many)

CUSTOMER SERVICE
Things To Consider

- BILLING
  - Bill Layout and Design

    Must Be Easily Read and Understood
    - YOU Decide How Much Information You Want the Customer to know

Walton EMC

ELECTRIC MEMBERSHIP CORPORATION
P O Box 1347 Monroe, GA 30655-1347

Monroe	Snellville	Watkinsville
842 Hwy 78 NW	3645 Lenora Church Rd	7911 Hwy 441 N
770/267 2505	770/972 2917	706/769-5622

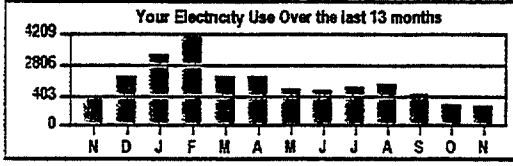
ACCOUNT NUMBER	NAME	RATE	CYCLE	TELEPHONE	SERVICE ADDRESS
20011802	BAKER TERESA	22	100	(706) 259-2821	BEAVERDALE RD 1463

SERVICE FROM	SERVICE TO	NO DAYS	BC	METER READING LAST BILL	METER READING THIS BILL	MULTIPLIER	KWH USAGE	$ AMOUNT
10/04/96	11/05/96	32	0	35194	36154	1	960	55.86
STATE TAX								2.24
LOCAL TAX								0.56
TOTAL CURRENT BILL DUE				12/05/96				58.66
PREVIOUS AMOUNT DUE								60.67
THANK YOU FOR YOUR PAYMENT				11/01/96				-60.67
TOTAL AMOUNT DUE								58.66

COMPARISONS	DAYS ON BILL	KWH USED	AVG KWH/DAY	COST PER DAY
CURRENT BILLING PERIOD	32	960	30	1 74
PREVIOUS BILLING PERIOD	29	997	34	1 99
SAME PERIOD LAST YEAR	32	1343	41	2 37

TOTAL DUE	$ 58.66
PAST DUE AFTER	12/05/96

Your Electricity Use Over the last 13 months



PLEASE REFER TO YOUR TELEPHONE NUMBER LISTED ABOVE. IF THE NUMBER IS INCORRECT, PLEASE NOTIFY US HAVING CORRECT PHONE NUMBERS ENSURES MORE ACCURATE TRACKING DURING STORMS!!!!!!!!

TO REPORT A POWER OUTAGE
Call your local office day or night at the number listed on the top of this bill

ASK ABOUT THESE SERVICES

- *Bill payment by bank draft
- *Project Share
- *5% loans for heating/cooling
- *Levelized billing
- *Equipment rebates
- *Lightning protection

*Past due date is for CURRENT month's bill only
*Any account with a previous amount due is subject to disconnection

Keep this statement for your records

PLEASE DETACH AND RETURN THIS PORTION WITH PAYMENT

0907-1196-01-000001

Walton EMC
ELECTRIC MEMBERSHIP CORPORATION
P O Box 1347
Monroe, GA 30655-1347

CASHIER'S RECEIPT

METER NUMBER	BC	CYCLE	ACCOUNT NUMBER
47752922	0	100	20011802
BILLING DATE	DUE DATE		AMOUNT DUE
11/11/96	12/05/96		58 66

ENTER AMOUNT PAID _____

FORWARDING AND ADDRESS CORRECTION REQUESTED
*********ENDORSEMENT*********
BAKER TERESA

PO BOX 3312
DALTON GA 30719-0312

WALTON EMC
P O BOX 1347
MONROE, GA 30655-1347

0020011802 00000005866 00000006145 7

563

North Georgia Electric Membership Corporation

1850 Cleveland Highway - P O Box 1407 - Dalton, GA 30722-1407
DALTON (706)259-9441 FT OGLETHORPE (706) 806-2231 CALHOUN (706) 629-3160 SUMMERVILLE (706) 734-7341

ACCOUNT NUMBER	ACCOUNT NAME	RATE	BC	TELEPHONE	SERVICE ADDRESS
20476102	JACOBS DAVID H	22	0	(706) 937-7214	HWY 41 2555

READING PREVIOUS	READING PRESENT	SERVICE FROM	SERVICE TO	MULTIPLIER	KWH	$ AMOUNT
52788	53992	10/04/96	11/05/96	1	1204	68.53
LOCAL TAX						1 37
STATE TAX						2.75
TOTAL CURRENT BILL DUE		12/05/96				72.65
PREVIOUS AMOUNT DUE						49.40
THANK YOU FOR YOUR PAYMENT		11/05/96				-49.40
TOTAL AMOUNT DUE						72.65

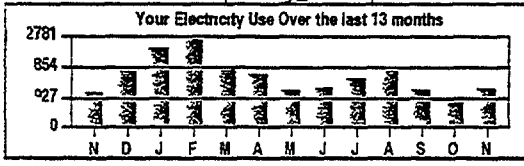
COMPARISONS	DAYS SERVICE	TOTAL KWH	AVG KWH/DAY	COST PER DAY
CURRENT BILLING PERIOD	32	1204	37	2 14
PREVIOUS BILLING PERIOD	29	782	26	1 61
SAME PERIOD LAST YEAR	32	1102	34	1 98

TOTAL DUE $ 72.65

DUE DATE 12/05/96 BILL IS DELINQUENT AFTER DUE DATE

AFTER DUE DATE PAY $ 76 07

Your Electricity Use Over the last 13 months



PLEASE REFER TO YOUR TELEPHONE NUMBER LISTED ABOVE IF THE NUMBER IS INCORRECT, PLEASE NOTIFY US HAVING CORRECT PHONE NUMBERS ENSURES MORE ACCURATE TRACKING DURING STORMS!!!!!!!

0907-1196-01-000002

DID YOU KNOW?
These customer services are available for you
Bank Draft
Levelized Billing
Banks Accept Bill Payments
Outdoor Lighting
Energy Services Programs
Social Security Net Payment

> Write your account number on your check to ensure accurate posting of your payment.
> Allow ample time for delivery before the due date when mailing your payment.
> Outside depository is available after hours

NOTICE THIS BILL IS PAYABLE IN FULL WHEN MAILED THE ACCOUNT IS SUBJECT TO DISCONNECTION WITHOUT FURTHER NOTICE IF PAYMENT IS NOT RECEIVED IN THE COOPERATIVE OFFICE PRIOR TO THE DUE DATE

RETAIN THIS COPY FOR YOUR RECORDS

PLEASE DETACH AND RETURN THIS PORTION WITH PAYMENT

BILLING DATE		ACCOUNT NUMBER	DUE NOW
11/11/96		20476102	72 65
BC	RATE	DUE DATE	AFTER DUE DATE
0	22	12/05/96	76 07

PLEASE INDICATE CHANGE OF ADDRESS OR PHONE NUMBER HERE

NORTH GEORGIA ELECTRIC MEMBERSHIP CORPORATION
1850 CLEVELAND HIGHWAY P O BOX 1407
DALTON, GA 30722 1407

FOR WARDING AND ADDRESS CORRECTION REQUESTED
********ENDORSEMENT*********

JACOBS DAVID H

2555 HIGHWAY 41
RINGGOLD GA 30736-6142

NORTH GEORGIA ELECTRIC MEMBERSHIP CORP
P O BOX 1407
DALTON, GA 30722 1407

0020476102 00000007265 00000007607 2

564

CUSTOMER SERVICE
Things To Consider

- BILLING
  - Information on the Bill
    - Meter Reading
    - From / To Dates
    - Total Usage
    - Due Date
    - Past Due Date
    - Disconnect Date

CUSTOMER SERVICE
Things To Consider

- BILLING
  - Other Helpful Information
    - Usage Last Month
    - Usage One Year Ago
    - Average Daily Usage
    - Advertisement of Other Services
  - "Thank You" For Previous Payment

PEACE RIVER ELECTRIC COOPERATIVE, INC.

P O BOX 1310 WAUCHULA, FL 33873-1310

ELLENTON (941) 722 2729 WAUCHULA (941) 773-4116 INDIAN LAKE ESTATES (941) 692 1152
Office Hours 8:00 a m to 4.30 p m Monday through Friday

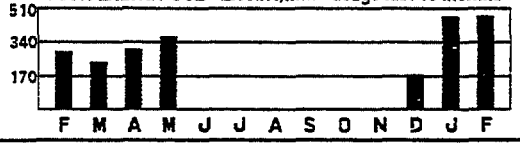
ACCOUNT NUMBER	NAME	RATE	CLASS	TELEPHONE	LOCATION NUMBER	METER NUMBER
4649701	CRIPPS HARRIET & ARTHUR	2	1	(813) 767-0816	3605007120	26623920

SERVICE FROM	SERVICE TO	NO DAYS	TYPE BILL	READING PREVIOUS	READING PRESENT	MULTIPLIER	KWH USAGE	CHARGES
01/04/96	02/06/96	33	R	4283	4772	1	489	45 23
	BASE RATE CHARGE							10 50
- 010000	FUEL						489	-4 89
	OTHER AMOUNT (1)							- 07
	TAX - GROSS							1 30
	TOTAL CURRENT BILL DUE				02/21/96			52 07
	OVERPAYMENT AMOUNT							-16 85
	TOTAL AMOUNT DUE							35 22

COMPARISONS	DAYS SERVICE	TOTAL KWH	AVG. KWH/DAY	COST PER DAY
CURRENT BILLING PERIOD	33	489	14	1 54
PREVIOUS BILLING PERIOD	30	489	16	1 69
SAME PERIOD LAST YEAR	29	311	10	1 30

TOTAL DUE NOW $ 35 22

YOUR ENERGY USE Electric/kwh usage last 13 months



PREC01

NOTICE THIS BILL IS PAYABLE IN FULL WHEN MAILED THE ACCOUNT IS SUBJECT TO DISCONNECTION WITHOUT FURTHER NOTICE IF PAYMENT IS NOT RECEIVED IN THE COOPERATIVE OFFICE PRIOR TO THE PAST DUE DATE THERE IS NO GRACE PERIOD AFTER THE PAST DUE DATE

TYPE BILL	DESCRIPTION
0	NORMAL
1	ESTIMATED
2	MINIMUM ESTIMATED
3	MINIMUM
4	FINAL
5	PRORATED
6	PRORATED MINIMUM
7	LEVELIZED BILL
8	CONTRACT

RETAIN THIS COPY FOR YOUR RECORDS

PLEASE DETACH AND RETURN THIS PORTION WITH PAYMENT

CASHIER'S RECEIPT 460

ACCOUNT NUMBER	DUE DATE		AMOUNT DUE
4649701	02/21/96		35.22
BILLING DATE		RATE	METER NUMBER
02/06/96	00	2	26623920

Peace River Electric Cooperative, Inc
P O BOX 1310 WAUCHULA, FL 33873 1310
(800) 282 3824

FORWARDING AND ADDRESS CORRECTION REQUESTED

ENTER AMOUNT PAID _____

306-SN 1

CRIPPS HARRIET & ARTHUR
LOT 143
RT 3 BOX 70
BOWLING GR 33834-0000

PEACE RIVER ELECTRIC COOPERATIVE INC INC
P O BOX 1310
WAUCHULA FL 33873-1310

0004649701 00000003522 00000003522 7

567

MOON LAKE ELECTRIC ASSOCIATION, INC.

P O BOX 337 ROOSEVELT, UT 84066-0337

Roosevelt (801) 722-2448 Rangely (970) 675-2291 Duchesne (801) 738-5322 Altamont (801) 454-3611 Jensen (801) 789-0424

Office Hours 7:00 a m to 5 30p m Monday through Thursday

ACCOUNT NUMBER	SERVICE LOCATION	READINGS	RATE / KWH	BILLED DEMAND	CURRENT BILL	TAXES	INTEREST	PAST DUE	TOTAL DUE
4926501 1	8A1E	60607 72431	13 11824	24 150	734 50	00	00	00	734 50
4926502 1	28A1	79787 85467	13 5680	25 040	515 74	00	00	00	515 74
4926503 1	33Z2	25587 36392	13 10805	23 000	683 95	00	00	00	683 95
4926504 2	33Z2 UTE	2552 2552	13 0	000	241.00	.00	.00	.00	241.00
4926505 1	32Z2	31634 62091	13 30457	61 010	1833.11	00	00	00	1833 11
4926506 2	5B2 LAMICQ	15887 45688	13 29801	45 140	1634 14	00	00	00	1634.14
4926507 1	6B2	80380 94989	13 14609	27 400	873.85	00	00	00	873 85
4926508 2	6B2 UTE	28967 50102	13 21135	45 280	1313 30	00	00	00	1313 30
4926509 1	31A2	15833 24243	13 8410	41 000	792 85	.00	00	00	792.85
4926510 1	17B5 BATTERY	22165 27477	8 5312	18 840	345 13	00	00	00	345 13
4926511 2	13B2 MATTHEWS	38719 57458	13 18739	33 990	1099 98	00	00	00	1099.98

BILLING DATE	DUE DATE	SERVICE DATES	TOTAL AMOUNT DUE $146,401 16
08/29/96	09/20/96	07/17/96 08/26/96	

FOR POWER OUTAGES AND EMERGENCIES - 24 HOURS

(801) 722-2448 1 (800) 437-9056

FOR YOUR SAFETY-- THINK OF SAFETY WHEN AROUND ELECTRICITY IT CAN HELP YOU AVOID THE SHOCK OF YOUR LIFE!!

SEDC-MNL01 A

RATE CODES

- Residential
- 2 Seasonal
- 3 Yard Light
- General Service Single Phase
- 8 General Service Three Phase
- Street Lighting
- 12 Irrigation
- 13 Large Power
- 14 Industrial
- 15 Large Power Primary
- 16 IS-1 Oil Field Pumping
- 17 Large Power Secondary

METER READING CODES

- R Regular Meter Reading
- E Estimated Meter Reading *
- M Meter Changed

OFFICE LOCATIONS

ROOSEVELT UT (MAIN OFFICE) 188 WEST 200 NORTH
RANGELY CO 1635 EAST MAIN
DUCHESNE UT 184 NORTH CENTER
ALTAMONT UT MAIN STREET

* Usage is occasionally estimated due to weather conditions, unforeseen circumstances, or for certain types of seasonal loads. Actual meter readings will be taken and your bill will be adjusted automatically if necessary

IMPORTANT INFORMATION

PAYING YOUR BILL. Please pay this bill as soon as you receive it. Return your payment in the enclosed envelope or in person at any MOON LAKE ELECTRIC ASSOCIATION INC office. Recent payments may not have been deducted from your bill
PAST DUE BILLS. An unpaid bill becomes delinquent 20 days after billing date and subject to a 1% penalty If you are unable to pay this bill please call the telephone number on the top of this bill or come to any Moon Lake Electric Association, Inc. office to discuss a payment agreement.
RETURN CHECKS We will charge you a $10 00 fee if your check is returned from the bank unpaid.
To report a POWER OUTAGE CALL your Cooperative local office listed above or call 1-800-437-9056.

RETAIN THIS COPY FOR YOUR RECORDS

PLEASE DETACH AND RETURN THIS PORTION WITH PAYMENT

Moon Lake Electric Association, Inc

P O BOX 337 ROOSEVELT UT 84066-0337

Roosevelt (801) 722 2448 Rangely (970) 675-2291 Duchesne (801) 738-5322 Altamont (801) 454-3611 Jensen (801) 789-0424

CASHIER'S RECEIPT

CUSTOMER NUMBER	DUE DATE	AMOUNT DUE
49265	09/20/96	146,401 16
BILLING DATE	PAST DUE AFTER	
08/29/96		

SUMMARY BILL

ADDRESS CORRECTION REQUESTED

1048-SN 133

ANR PRODUCTION CO
PO BOX 749
DENVER CO 80201-0749

ENTER AMOUNT PAID _____

MOON LAKE ELECTRIC ASSOCIATION INC
P O BOX 337
ROOSEVELT, UT 84066-0337

568

ELECTRIC STATEMENT

MOON LAKE ELECTRIC ASSOCIATION, INC.

P O BOX 337 ROOSEVELT, UT 84066-0337
1-800-437-9056
Office Hours 7 00 a m to 5 30p.m Monday through Thursday
Roosevelt (801) 722-2448 Rangely (970) 675-2291 Duchesne (801) 738-5322 Altamont (801) 454-3611 Jensen (801) 789-0424

ACCOUNT # 49265

ACCOUNT NUMBER	SERVICE LOCATION	READINGS	RATE KWH	BILLED DEMAND	CURRENT BILL	TAXES	INTEREST	PAST DUE	TOTAL DUE
49265121	18B1 3-37 1/	44897 59874	13 14977	38.000	1004 14	.00	.00	.00	1004.14
49265131	13B2	51079 78980	13 27901	66.000	1792 92	.00	00	.00	1792.92
49265141	19B1	1570 1570	13 0	000	241.00	.00	00	.00	241.00
49265151	31B5	37290 62988	13 25698	41 000	1435 97	.00	00	.00	1435 97
49265162	32B5 BROADHEA	32918 66821	13 33903	79.110	2160 40	.00	.00	.00	2160.40
49265171	32B5 BROADHEA	97394 12262	13 14868	29.000	901 09	.00	00	.00	901.09
49265182	34B5 DUNCAN M	49509 97948	13 48439	76.500	2672 43	00	.00	.00	2672.43
49265192	29B5 ROBB	76394 99889	13 23495	57 550	1536.06	.00	.00	.00	1536.06
49265211	25B6 BATTERY	97913 1645	13 3732	15.000	332.83	.00	.00	.00	332.83
49265221	36B6	16515 38203	13 21688	39.220	1267 21	.00	.00	.00	1267.21
49265231	28B6X UTE	50329 76421	13 26092	41.480	1455 90	.00	.00	.00	1455.90
49265242	21B6 UTE TRIB	32456 32456	13 0	.000	241.00	.00	.00	.00	241.00
49265251	27B16	54017 60809	13 6792	27.990	589.55	.00	.00	.00	589 55
49265261	21B6 BROADHEA	31712 61116	13 29404	48 000	1650.83	.00	.00	.00	1650.83
49265283	27B5 UTAHN	47307 85025	13 37718	54.000	2026 11	.00	.00	.00	2026.11
49265321	34B5 DUNCAN M	96324 96332	8 8	.000	15 75	.00	.00	.00	15 75
49265332	27B5 SWD	22653 60427	13 37774	111 970	2665.86	156.62	.00	.00	2822 48
49265352	22B5	9259 39542	13 30283	52 010	1727.64	.00	00	.00	1727 64
49265361	36A4 UTE	68420 19993	13 51573	75 000	2772.52	.00	00	00	2772 52
49265371	35A4 MILES	26854 26854	13 0	000	241 00	00	00	00	241 00
49265381	2B4 BROTHERSO	47207 98062	13 50855	74 330	2738 44	00	00	00	2738 44
49265392	35A4	82234 273	13 41502	154 920	4211 53	00	00	00	4211 53
49265401	34A4 UTE LAKE	55002 80943	13 25941	44 360	1481 97	00	00	00	1481 97
49265412	2B4	47240 129	13 39601	201 840	4907 63	00	00	00	4907 63
49265422	2B4 1 11B4 P	8552 8760	13 8320	24 000	602 50	00	00	00	602 50
49265432	12B4 BROTHERS	32136 33732	13 95760	180 600	5577 87	00	00	00	5577 87
49265442	11B4 BROTHERS	62256 10153	13 47897	73 870	2623 34	00	00	00	2623 34
49265451	14B4 BROTHERS	95874 16847	13 20973	39 000	1238 20	00	00	00	1238 20
49265462	13B4 LAKEFORK	73689 21286	13 47597	71 200	2582 81	00	00	00	2582 81

TOTAL DUE NOW $ 146,401 16

SF-C01 MNL02

569

ELECTRIC STATEMENT

MOON LAKE ELECTRIC ASSOCIATION, INC.

P O BOX 337 ROOSEVELT, UT 84066-0337

1-800-437-9056

Office Hours 7·00 a m to 5 30p m Monday through Thursday

Roosevelt (801) 722-2448 Rangely (970) 675-2291 Duchesne (801) 738-5322 Altamont (801) 454-3611 Jensen (801) 789-0424

ACCOUNT # 49265

ACCOUNT NUMBER	SERVICE LOCATION	READINGS	RATE KWH	BILLED DEMAND	CURRENT BILL	TAXES	INTEREST	PAST DUE	TOTAL DUE
49265471	24B4	36921 48988	13 12067	29.790	805 58	.00	.00	.00	805 58
49265481	23B4 BROTHERS	84281 11526	13 27245	37.820	1458.53	.00	.00	.00	1458.53
49265492	23B4 SWD	35378 36610	13 49280	156.000	3578.22	210.22	.00	.00	3788.44
49265501	23 BROTHERSON	91416 32328	13 40912	56.520	2172 65	.00	00	.00	2172 65
49265511	26B4	25667 49288	13 23621	36.380	1307.88	.00	.00	.00	1307.88
49265523	23B4 BROTHERS	40641 68995	13 28354	46.920	1599.89	.00	.00	.00	1599 89
49265531	22B4 BROTHERS	96563 96563	13 0	.000	241.00	00	.00	.00	241.00
49265542	22B4 BROTHERS	76008 27994	13 51986	75.320	2791 40	.00	00	.00	2791.40
49265551	28B4	49777 70780	13 21003	30.220	1142.73	.00	.00	.00	1142.73
49265561	20B4	17096 44000	13 26904	49.000	1568 83	.00	00	.00	1568 83
49265571	21B4 HUNT	31567 64056	13 32489	50.090	1788.58	.00	.00	00	1788.58
49265581	21B4 HUNT	81477 3621	13 22144	34.410	1231.27	.00	00	00	1231.27
49265592	15B4 BROTHERS	33294 72914	13 39620	53.910	2095.87	.00	00	.00	2095.87
49265601	16B4 ELLSWORT	18468 53960	13 35492	63.600	2048 90	.00	00	.00	2048 90
49265612	16B4 ELLSWORT	4753 51416	13 46663	68.380	2517.04	.00	.00	00	2517.04
49265623	15B4 LAKEFORK	3135 21923	13 18788	30.520	1063 63	.00	00	.00	1063 63
49265632	14B4 BROTHERS	77551 1823	13 81700	166.640	5227.90	00	00	00	5227 90
49265652	33A4 LINDSAY	82186 32543	13 50357	74 150	2717 93	00	00	.00	2717 93
49265661	33A4 BROTHERS	58232 62631	13 4399	9 790	300 33	.00	00	00	300 33
49265672	34A4 UTE	85732 26923	13 41191	69 680	2327 79	00	00	00	2327 79
49265682	27A4 SALT WTR	7239 7926	13 41220	86 820	2517 40	147 89	00	00	2665 29
49265691	28A4	13807 44480	8 30673	000	1920 04	00	00	00	1920 04
49265701	28A4 BROTHERS	38734 44314	13 5580	20 280	459 66	00	00	00	459 66
49265712	28A4 FIELDSTE	68147 93960	13 25813	48 930	1527 47	00	00	00	1527 47
49265722	21A4 JESSEN	60190 83347	13 23157	49 920	1439 56	00	00	00	1439 56
49265731	21A4 CHATWIN	5843 14899	13 9056	22 000	607 88	00	00	00	607 88
49265742	29A4 CHRISTEN	8859 37050	13 28191	41 280	1531 79	00	00	00	1531 79
49265751	TEW 1-1B5 TANK	59753 95619	13 35866	60 460	2028 28	00	00	00	2028 28
49265761	1B5	55032 56648	13 1616	32 000	441 12	00	00	00	441 12

TOTAL DUE NOW $ 146,401 16

570

ELECTRIC STATEMENT

MOON LAKE ELECTRIC ASSOCIATION, INC.

P O BOX 337 ROOSEVELT, UT 84066-0337
1-800-437-9056
Office Hours 7·00 a m to 5 30p m Monday through Thursday
Roosevelt (801) 722-2448 Rangely (970) 675-2291 Duchesne (801) 738-5322 Altamont (801) 454-3611 Jensen (801) 789-0424

ACCOUNT # 49265

ACCOUNT NUMBER	SERVICE LOCATION	READINGS	RATE KWH	BILLED DEMAND	CURRENT BILL	TAXES	INTEREST	PAST DUE	TOTAL DUE
49265771	6B4 CROOK	72489 78666	13 6177	41.220	712.20	.00	.00	.00	712.20
49265781	5B4 CHANDLER	61797 94467	13 32670	69.150	2004.97	.00	00	.00	2004.97
49265792	1B5 MILES	52296 88148	13 35852	51 420	1928.31	.00	.00	.00	1928.31
49265802	6B4 POTTER	19548 43170	13 23622	34 640	1288.78	.00	.00	.00	1288.78
49265812	2B5 BROTHERSO	69610 88062	13 18452	42.290	1180.60	.00	00	.00	1180.60
49265821	2B5 POTTER	6690 38609	13 31919	46.920	1732.51	.00	00	.00	1732.51
49265831	9B5 DUNCAN TE	6327 6557	13 23000	66.000	1610.60	.00	.00	.00	1610.60
49265841	17B5	36737 38821	13 2084	39 000	535.52	.00	.00	.00	535.52
49265852	9B5 DUNCAN	1614 13085	13 11471	59.930	1114 95	.00	.00	.00	1114.95
49265862	15B5 BURTON	65087 78477	13 13390	64.480	1236 39	.00	.00	.00	1236.39
49265872	10B5 TEW	51492 64952	13 13460	69.720	1296 63	.00	.00	.00	1296.63
49265902	11B5 SALT WAT	4525 5271	13 59680	148.800	3885 90	228.30	00	.00	4114.20
49265912	7B4 FARNSWORT	16262 16262	13 0	.000	241.00	.00	.00	.00	241.00
49265921	12B5 FARNSWOR	88832 20377	13 31545	46.050	1709.02	.00	.00	.00	1709.02
49265931	7B4 FARNSWORT	26511 82903	13 56392	87.360	3087.74	.00	.00	.00	3087 74
49265941	8B4 ELLSWORTH	6506 10261	13 3755	9.000	267.69	.00	00	.00	267 69
49265951	9B4 ELLSWORTH	21810 22603	13 47580	89 400	2782.38	.00	00	00	2782 38
49265961	10B4 BROTHERS	18948 64466	13 45518	74 680	2543 75	00	.00	.00	2543 75
49265972	10B4	82706 95059	13 12353	42 260	953.39	00	00	00	953 39
49265981	17B4 ELLSWORT	17742 17742	13 0	000	241 00	00	00	00	241 00
49265992	17B4 ELLSWORT	17812 56082	13 38270	57 360	2083 60	00	00	00	2083 60

TOTAL DUE NOW $ 146,401 16

SEDC01 MNL02

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CUSTOMER SERVICE
Other Items on the Bill

- Additional Services Billed
  - Streetlights
  - Lightning Protection
  - Internet
  - Other Items Offered for Sale or Lease

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CUSTOMER SERVICE
Consolidated Billing

- A Summation of Multiple Accounts
  - Consolidation Within The Same Cycle
  - Consolidation Across Cycles
- What About Aggregate Billing?

SAWNEE ELECTRIC MEMBERSH. CORPORATION

ES CABLISHMENT OF BILLING CYCLE

I OBJECTIVE

A To provide an efficient and effective billing system so that, if desired, a consumer/member will only receive one bill per month

B To provide a reasonable degree of flexibility in the daily billing process to, within limit accommodate unique needs of our member/owners

II PROCEDURE

A STANDARD BILLING CYCLE SELECTION

Except as outlined in the Non-Standard Billing Cycle Section, all accounts will be bille as prescribed by the Cooperative This includes the general rules for reading an unt, processing the reading, and producing a billing statem Therefore, the rea g and billing cycle will be directly linked and will be the sam

B NON-STANDARD BILLING CYCLE SELECTION

The Corporation will, as outlined herein, provide a system of allowing the reading cycle and the billing cycle to be unlinked and have a unique relationship Shown below are the categories, time limitations and qualifications to participate in this program

1 CATEGORIES

These guidelines are divided into six (6) unique categories which are considered to be covered by this outline These categories are exclusive and not to be dependent on any other category

a General Principles

1) There will be no crossing of accounting months through this process (Cycle "K" to Cycle "J") This will ensure that only twelve (12) bills are issued in any calendar year

2) Accounts with service in a billing period, in which the service was for less than a full period, will be prorated as outlined herein When prorating occurs, accounts will be prorated based on the number of days in service relative to the meter reading date The prorating schedule shall be

a) Period 1 (0 – 29 days) The number of days in service from the "on date" to the "meter read" date divided by 30, multiplied times the base charge for the applicable rate

b) Period 2 (30 or 31 days) The full base charge applicable to this rate schedule will apply

3 All applicable calculations, as they relate to the various rate schedules, will be based on the date read All other variables (e g due date) will be based on the date invoiced

b Elderly/Fixed Income

When, based on the Corporation's guidelines, it is determined that a person is receiving some form of fixed income such as, but not limited to, social security income or other forms of payment which are received on the first (1st) and fifteenth (15th) of each month, their account will be moved to the billing cycle nearest their current cycle on either of the two (2) cycles (i e , if normally billed on the 28th of the month, it will be moved to the 30th of the month)

c Consolidated Billing

Consolidated Billing will be used when a member has more than one account to be billed in an accounting month The Corporation will consolidate all of a member's bills into a single monthly bill, unless specifically told by the consumer not to do so Multiple bills will be billed on the last applicable billing cycle in an accounting month This means, if a member has an account in cycle "B" and in Cycle "T", the controlling cycle will be "B" given the accounting period "K" to "J"

d Special/Limited Income Situations

The Corporation will allow consumers, upon request, to move their billing date by no more than seven (7) days This option will allow the consumer to select his/her billing date within the program's specific and limited guidelines By selecting a later date, the customer, in a sense, selects a new/alternate billing cycle

e Governmental Agencies (Federal, State or Local)

Governmental Agencies will be consolidated to a date that supports the timely payment of a single bill This billing cycle will be specified by the respective department within a specific agency and adhere to the general guidelines outlined herein

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f Special Load Types

"Customer Choice" consumers with load greater than 900 kW, as defined under the State of Georgia's Territorial Electric Service Act of 1973, can be positioned to a unique cycle/billing period which meets their business needs This principle recognizes the unique and sometimes complex nature of their type of service

2 TIME LIMITATIONS

A meter billed outside of its normal billing cycle will only be allowed as outlined below

a The current member must make the request to move his/her billing cycle

b The request for a change in billing cycle is valid as long as the account is in the name of the person who originally requested it.

c Should the meter be disconnected for any reason, it will automatically revert back to its initial assigned billing cycle

3 QUALIFICATIONS

Only those members who have satisfactory credit, as defined by the Corporation, will be allowed to utilize the prescribed aspects of this program Should a member be disconnected due to field collection on a particular account, the account will be returned to its initial reading cycle for billing, excluding any consolidated bills

III ENFORCEMENT

It generally shall be the responsibility of the Office Services Department Manager and the Member Services Department Manager along with the various supervisors of these departments to enforce these guidelines The General Manager will oversee and as necessary ensure the general adherence to the guidelines The Safety and Human Resources Sections will ensure that all necessary documents are completed to comply with these guidelines as set forth

APPROVED	May 29, 1997	EFFECTIVE	May 29, 1997
REVISED	July 28, 1997	EFFECTIVE	July 28, 1997

CUSTOMER SERVICE
Payment of Bills

- Establish Billing Cycles
- Establish Billing Due Dates
- Disconnect Dates
- Late Fees
- Collections
- Notices

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

POLICY NO 302

SUBJECT SERVICE FEES

I OBJECTIVE

To establish reasonable fees to be charged for the various services offered the member-consumer and to establish a uniform procedure for administering these services and fees

II CONTENT

A TYPE OF SERVICE

1 Service Connection - A fee of $25 00 will be charged for the connection of initial connection of an existing service The fee is in addition to the membership fee and security deposit requirements No multiple fees shall apply for services in the same general proximity

2 Service Reconnection - A fee of $25 00 will be charged for the reconnection of any service that has been disconnected due to non-payment of charges accrued to the service account for electric service or other related charges or because of failure to comply with established rules and regulations of the Cooperative Other related charges are defined as membership fees, service security deposits, service fees, test fees, and fees charged for returned checks The application of this fee covers the termination of services whereby the application for service has not been properly executed as required by the rules and regulations of the cooperative No reconnection fee will be charged the first time an account is reconnected in association with the first field collection

3 Collection - A fee of $25 00 will be charged for the field collection of electric service charges or other related charges This fee is in addition to any outstanding charges due at the time Only one fee is applicable at each collection location No collection fee will be charged the first time an account is field collected

4 Late Payment - The Corporation will assess a late payment fee of $5 00 to all accounts for payments made after the due date shown on the statement provided This fee is in addition to any outstanding charges due at the time No late fee will be charged for the first time an account is considered late

5 Returned Checks - A fee of $20 00 will be charged to the electric service account of any member-consumer for the processing of each unpaid personal check returned by their bank.

6 Meter Tests - A service fee will be charged for meters tested more frequently than every 12 months when requested by the member-consumer for the verification of the accuracy of the meter The following schedule of fees will apply

Single Phase Meters	$25 00
Multi-Phase Meters	$50 00

Member-consumers requesting that meter tests be conducted by an outside testing firm will be required to pay a minimum fee of $25 00 plus any other charges billed to the cooperative for the test

7 Miscellaneous

a. A service charge of $25 00 may be made for service calls made by cooperative personnel for investigation of any service problems or interruptions when the cause is found to be due to problems with equipment owned by the consumer

b A service charge of $25 00 may be made for service calls made in response to a consumer's request for the connection, reconnection, or disconnection of their electric service if the consumer withdraws such request after the service call has been made or after the serviceman has been dispatched to the account

B EXTRA CHARGES

The amount of the service fees described in this policy apply to services provided during regular working hours which are from 8 00 a m to 5 00 p m , Monday through Friday For services provided after regular working hours, weekends, and holidays, a charge of $40 00 will be made in addition to the regular fee amount

III RESPONSIBILITY

It shall be the responsibility of the General Manager to administer this policy, to develop appropriate controls for its overall enforcement and to report his findings to the Board of Directors

ADOPTED	01/10/89	EFFECTIVE	06/01/89
REVISED	12/20/90		
	04/18/91		
	11/21/91		
	12/16/93		
	11/17/94	EFFECTIVE	11/17/94
	05/18/95	EFFECTIVE	05/18/95
	01/16/97	EFFECTIVE	03/03/97

CUSTOMER SERVICE
Methods of Payment

- Cash
- Check
- Credit Cards
- Automatic Account Debits
  - Credit Cards
  - Bank Accounts
- Budget Billing
- Arranged Payment
  - How Many
  - How Often
  - How Much

CUSTOMER SERVICE
Applications For New Service

- Current Address
- New Address
- Billing Address
- Identification Number
- Signed Application
- Type of Service
- Size Of Service
- Date Service to be Completed
- New Service Fees
- Phone Numbers
- Directions to New Location
- Household Information

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CUSTOMER SERVICE
Applications for New Service

- Deposits
- Appliance Data
- Business Phone
- Balance From Prior Accounts
- Credit Rating
- Governmental Inspections
- Right-Of-Way Easements
- As Much Data As Possible

CUSTOMER SERVICE
Deposit

- Are / Are Not Required
- Letters of Credit From Other Utility
- When To Return Deposit
- Return With/Without Interest
- Guidelines for Return
  - One or More Late Notice
  - One or More Disconnects

CUSTOMER SERVICE
Deposits

- How Long to Keep?
- Can Deposits Be Waived
- Who Can Waive

1.85

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

POLICY NO. 307

SUBJECT SERVICE SECURITY DEPOSITS

I OBJECTIVE

The purpose of this policy is to outline the conditions under which credit is extended and secured. The security deposit will serve to secure debt and the service rules to be used are described herein

II CONTENT

For each and every service connection, except as herein provided, a service security deposit, or an increase thereof, will be collected either in advance or immediately after the connection of the electric service The amount of the deposit, or any exceptions to the payment of a deposit, is set forth in Appendix "A" of this policy

Determining the need for and fixing the amount of service security deposits will be based on the Cooperative giving careful consideration to the following factors

A. Type of risk involved,

B Risk involved in a new business enterprise,

C Credit status of the applicant,

D Any other factor having a realistic bearing on the consumer's financial dependability

NO INTEREST

No interest shall be paid by the Cooperative on Service Security Deposits

REFUNDS

Service Security Deposits will be refunded by first applying them to any outstanding debt owed to the Cooperative and then any unused funds will be returned to the consumer under the following circumstances

A As provided for in a written contract for service

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B After twenty-four (24) consecutive months of continuous electric service provided a satisfactory Credit Rating (*) has been established

C Or upon such other conditions as may be established by the Cooperative

(*) CREDIT RATING A satisfactory credit rating is defined as the account of a consumer having no record of being field collected, having no checks returned unpaid by their bank for any reason, nor having been disconnected for non-payment of account.

III ESPONSIBILITY

It shall be the responsibility of the General Manag to administer this policy, to develop appropriate controls for its overall enforcement and to report his findings to the Board of Directors

ADOPT	11/02/78	ECTIVE	01/01/79		
REVISED	04/09/79	REVISED	05/18/95	EFFECTIVE	05/18/95
	10/18/79		01/16/97	EFFECTIVE	02/03/97
	01/21/82				
	07/21/83				
	10/18/90				
	04/18/91				
	05/21/92				
	11/19/92				
	07/15/93				
	12/16/93				

APPENDIX "A"

SERVICE SECURITY DEPOSITS

1 Service security deposits will not be required under the following circumstances

A When an existing consumer has established a satisfactory credit rating for the specified period and is requesting an additional service or is relocating to another account

B When a former consumer with a satisfactory credit rating for the specified period requests service either at the original location or a new location

C When, upon request of an applicant, the Cooperative shall review the applicants credit history to determine the credit rating of the applicant (If the credit history, twelve (12) months as provided by a letter of credit from the applicant's previous electric supplier(s), supports the satisfactory credit rating, no deposit will be required)

D When, upon request of an applicant, the Cooperative shall consider the credit history of an account reported in the name of the applicant's spouse or former spouse when the applicant can demonstrate that the spouse's credit reflects the applicant's satisfactory credit rating and is for the specified period

E Service security deposits will not be required for service to agencies and divisions of the federal and state governments, municipalities, and counties, unless required under special agreements or contracts for service

F Service security deposits will not be required for service to local and national community action groups and community service programs designated to improve the general opportunities for minorities, females, and other protected groups in support of Sawnee EMC's Affirmative Action Plan

2 Service security deposits will be required under the following circumstances

A RESIDENTIAL

1 Given the inability to meet the above requirements, a new consumer will pay a minimum service security deposit of $100 00 within a reasonable period of time after receiving electrical service

2 Former consumers with unsatisfactory credit rating will pay a service security deposit equal to 100% of any outstanding amount then due the Cooperative (rounded to the nearest $1 00) with a **minimum** deposit of $100 00, **plus** the outstanding amount then due the Cooperative, prior to receiving electrical service

3 Existing consumers with an unsatisfactory credit rating will be required to pay any outstanding past due amount then due the Cooperative on his/her current account **and** may be required to pay a security deposit of between $100 and $200 depending on the number of times collected or disconnected within a 24 month period, prior to receiving electrical service Should the consumer already have a deposit which is less than the deposit required and is required to pay an additional deposit, that deposit will be increased

4 Multiple accounts with unsatisfactory credit rating will be required to pay a service security deposit equaling the lesser of 100% of the average monthly charges or $100 00 per service point. In no case will the charges be less than $100 00

B COMMERCIAL

1 Single Phase Service - Small Commercial

a A new commercial applicant requesting a new service or the reconnection of a former service, will pay a service security deposit of $200 00 or an amount equal to two (2) months bill, whichever is greater, within a reasonable time after receiving electrical service

b Former small commercial consumers with unsatisfactory credit ratings will pay a service security deposit equal to 100% of any amounts then due the Cooperative (rounded to the nearest $1 00) **and** a deposit of $200 00, plus any outstanding amount then due the Cooperative, prior to receiving electrical service

c Existing small commercial consumers with unsatisfactory credit ratings will be required to pay any outstanding past due amount then due the Cooperative on their current account **and** may be required to pay a security deposit of $200 00, prior to receiving electrical service Should the consumer already have a deposit which is less than the deposit required and is required to pay an additional deposit, that deposit will be increased

d Multiple small commercial consumers with unsatisfactory credit ratings will be required to pay a service security deposit equaling the lesser of 100% of the average monthly charges or $200 00 per service point In no case will be charges be less than $200 00

2 Multi-Phase Service - Large Commercial

The minimum service security deposit required under this type service will be determined pursuant to a written contract agreement and will equal two (2) months minimum charges

a. For new large commercial consumers where the minimum service deposit is not known at the time of application, the deposit will initially be $300 00 until such time the applicable deposit can be calculated, and this deposit must be paid immediately after receiving electrical service The consumer will be billed for any additional fees and will be required to pay these fees in no more than three (3) equal payments

b Former large commercial consumers with unsatisfactory credit ratings will pay a service security deposit equal to 100% of any amounts then due the Cooperative (rounded to the nearest $1 00) plus a deposit of $300 00, plus any outstanding amount then due the Cooperative, prior to receiving electrical service The consumer will be billed for any additional fees and will be required to pay these fees in no more than three (3) equal payments

c Existing large commercial consumers with unsatisfactory credit ratings will be required to pay any past due outstanding amount then due the Cooperative on their current account and may be required to pay a security deposit of $300 00, prior to receiving electrical service Should the consumer already have a deposit which is less than the deposit required and is required to pay an additional deposit, that deposit will be increased The consumer will be billed for any additional fees and will be required to pay these fees in no more than three (3) equal payments

CUSTOMER SERVICE
Disconnects

- MUST ESTABLISH SPECIFIC RULES AND GUIDELINES FOR DISCONNECTING SERVICE
- Requested Disconnects
  - Proper Authority to Request (Who)
  - Timing of Disconnect (When)
  - Final Billing Considerations

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CUSTOMER SERVICE
Disconnects

- Non Requested Disconnects
  - Non Payment Disconnects
  - Proper Notices
    - Late Notice
    - Disconnect Notice
  - Weather Constraints
  - Health Constraints
  - Age Constraints
  - Third Party Notification

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

POLICY NO 403

SUBJECT PAYMENTS, COLLECTIONS AND ARRANGEMENTS

I OBJECTIVE

To provide a consistent method for Sawnee's staff to make arrangements for delinquent accounts

To provide consumers every reasonable opportunity available to make payment arrangements and allow Sawnee to continue to provide electric service

II CONTENT

This policy is designed to serve as a guide for Sawnee's employees and management for both internal and external operating procedure

PAYMENT

The purpose of this policy is to state that the Corporation expects all bills, statements or other requests for payment to be made as requested No consumer should make payment with any instrument which is not negotiable Any consumer making payment to the Corporation with a check which causes them to establish unsatisfactory credit will lose their right to make future payments by check as defined in Policy 307, Service Security Deposits Applicable charges as outlined in Policy No 302, Service Fees, will apply for all returned checks, as well as the standards outlined in Policy 301, Service Security Deposits

ARRANGEMENTS

A Internal

The staff of Sawnee's Customer Service and Collection Sections will be assigned as the only groups which can make arrangements as it relates to a consumer's electric charges

B External

1 All members of Sawnee's Customer Service and Collection Sections of the Member Services Department can make payment arrangements under the following conditions

a Arrangements can only be made on balances less than 60 days old and when collection of the account occurs, all outstanding charges, excluding current charges not past due, will be collected

b Sawnee will keep a running total of the number of arrangements each consumer makes on each account for a 12 month period Each consumer will be allowed to make six (6) arrangements within a 12 month period for each account

c For outstanding balances, the following conditions will apply

Current Bills

Consumers will be allowed to make arrangements, within reasonable limits, on this balance

30-60 Days Past Due

Consumers will be limited on the level of arrangements which can be made on these balances The arrangements cannot exceed the lesser of either three (3) times the current bill or $1,000 00 and must be paid in full at the time agreed upon.

+ 60 Days Past Due

No arrangements or extensions will be made on these balances

d No arrangements will be made for payments on billing balances where payment is made by bad check and our records indicate having previously received two (2) checks returned for insufficient funds

2 Any exception to these standards can only be made with the permission of the designated Coordinators or the designated Department Managers No exceptions will be made when partial payment is received Partial payment constitutes the consumer failing to complete the arrangement conditions

3 All arrangements will be repeated back to each consumer after arrangements are agreed upon Whenever possible, written confirmation of arrangements will be forwarded to the consumer for his/her files All arrangements will be made on the Arrangement Payment Form

4 Extension will only be given in cases of hardship or emergencies In such case, we will allow only five (5) working days extension prior to service disconnection

COLLECTIONS

For outstanding balances, the following guidelines will apply

A Current Bill

Consumers will be allowed to remit payment as specified on the bill and no collection activity will occur if payment is received by the specified due date

B Past Due

An account will normally be considered to be delinquent/past due once the age of the balance has exceeded the date stated on the bill form All accounts which have a balance due in excess of the date stated on the bill form will be considered delinquent and subject to disconnect notice, field collection, and disconnection All charges, fees, and other conditions shall apply as specified

III RESPONSIBILITY

It shall be the responsibility of the General Manager to administer this policy, to develop appropriate controls for its overall enforcement and to report his findings to the Board of Directors

ADOPTED December 20, 1990

REVISED April 18, 1991
December 19, 1991
November 19, 1992
January 21, 1993
February 18, 1993
May 20, 1993
February 16, 1995
March 16, 1995
January 16, 1997 EFFECTIVE January 16, 1997

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CUSTOMER SERVICE
Miscellaneous Services

- What to Offer
- What to Charge
- How to Bill

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CUSTOMER SERVICE
Miscellaneous Services

- WHAT TO OFFER
  - Streetlights
  - Lightning Protection
  - Home Warranties
  - Internet Service
  - Home Inspection
  - Home Security

CUSTOMER SERVICE
Miscellaneous Services

- WHAT TO CHARGE
  - Decide Which Services Are Free
  - Up Front Payments or Monthly
  - Will You Disconnect for Non Payment
  - Develop Partnerships With Providers of These Services

SAW ELECTRIC MEMBERSHIP CORPORATION

POLI O. 308

SUBJECT: SENIOR CITIZEN DISCOUNT/REBATE PLAN

I C CTIVE

A To establish a process by which qualifying members receive a Board approved discount/rebate plan

B To define the controlling guidelines by which a Senior Citizen Discount/Rebate Plan is to be applied

II CONTENT

General

The Board of Directors of Sawnee EMC has given careful and deliber consideration to offering a Senior Citizen Discount/Rebate Plan as defined herein It is the belief of the Board that a discount/rebate plan is justified and appropriate

A The Senior Citizen Discount/Rebate Plan shall be limited and ed as outlined herein

B The qualifications for the plan are as follows

1 The application of e Plan will be limited to the primary residence (abode) of qualifying members

2 To qualify, the member must be at least 70 years of age er

3 The member must sign an affidavit (Exhibit A) to certify that they have a total annual income, which does not exceed $10,000, from all sources

4 The member must agree to allow Sawnee EMC to ver information given as needed

C The member must make this application either in person or via mail All documen must be signec the member If the member is not physically able to write, a guardian may exe the documents on the member's behalf, but in all cases the affidavit ust be essed.

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D Should the Corporation determine at any time that a participating member in the Plan does not meet the prescribed qualifications, the member will be terminated from the Plan

E The discount/rebate offered under this Plan shall be a billing credit of three dollars ($3 00) per month for each of the twelve months in a year Should the discount/rebate be stopped or started in a given year, it will begin as of the effective date and no retroactive or prospective service will be available

F The rebate can be changed or totally eliminated by Board action

G Under no circumstance will any account other than the member's primary residence (abode) be considered for this discount/rebate

III. RESPONSIBILITY

It shall be the responsibility of the General Manager, as directed by the Board of Directors, to administer this policy, to develop appropriate controls for its overall enforcement and to report his findings to the Board of Directors

ADOPTED March 24, 1997 EFFECTIVE April 1, 1997

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

SENIOR CITIZEN DISCOUNT/REBATE PLAN

EXHIBIT "A"

Member's Name_____ Account No _____

Address_____ Member No _____

_____ Social Security No _____

Sawnee Electric Membership Corporation offers a Senior Citizen Discount/Rebate Plan to members who qualify as outlined below

1 The Plan is limited to the residential primary residence (abode) for qualifying members

2 To qualify, the member must be at least 70 years of age or older

3 The member must sign an affidavit (Exhibit A) to certify that they have an annual income, which does not exceed $10,000, from all sources

4 The member must agree to allow Sawnee EMC to verify information given as needed

---

AGREEMENT

1 The above qualifications have been explained and discussed with me

2 I am at least 70 years of age, and receive less than $10,000 in total income annually

3 I am aware that I will still be subject to a late payment charge if payment is not made by the due date, and in the case of disconnection due to non-payment, I will be charged the applicable fees

4 I further authorize Sawnee EMC to verify this information from time to time, as required

_____ _____ _____

Member Signature Witness Signature Date

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CUSTOMER SERVICE
Miscellaneous Services

- FINALLY
  - How to Bill
  - No Subsidization by Other Consumers
  - Increases Your Presence With Consumers

CUSTOMER SERVICE
Billing Questions/Complaints

- THERE WILL BE MANY

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CUSTOMER SERVICE
Billing Questions/Complaints

- Important to Have a Knowledgeable Representative Available to Answer Specific Questions
- Person Should Be Able to Calculate the Various Rates
- Computer System Should Be Maintained to Input Data and Provide On-Line Calculation

CUSTOMER SERVICE
Billing Questions/Complaints

- Important For Commercial Rates Too
- Be Prepared To Answer Specific Questions About Anything Published in the Rate or On the Bill

CUSTOMER SERVICE
Outages

- Who Will the Consumer Call
- Where Will They Be
- What Information Should They Have to Notify Customer Service
- Important Information (Downed Lines, Trees, Etc.)
- What About Response Times

CUSTOMER SERVICE
Outages

- Will You Have 24-Hour Service
- Will You Have Crews On Call
- Preparedness for Major Disasters
- Surplus Material

CUSTOMER SERVICE
Metering

- THINGS TO CONSIDER
  - Accuracy of Meter
  - Routine Meter Maintenance
  - Frequency of Meter Reading
  - Who Will Read the Meter
    - Meter Reader
    - Customer
    - Automated Meter Reading (AMR)

CUSTOMER SERVICE
Miscellaneous

- Relocating Lines
- Cutting Trees
- Repair of Damages
- Blinking Lights

- ??????????? YOU NAME IT ????????

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

COPY

POLICY NO 411

SUBJECT: CUSTOMER SERVICE

I OBJECTIVE

A To support the theory that Sawnee Electric Membership Corporation is a cooperative which exists to serve the ever-changing needs of its member/owners

B To provide a general guideline to the Corporation's employees on how to support the member/owner in meeting the various service issues

II CONTENT

Sawnee Electric Membership Corporation exists as a rural electric cooperative to serve the member/owner The Corporation was founded on the basic principle of customer service and this policy exists to provide employees of the Corporation with direction on resolving disputes between the Corporation and its member/owners

A Claims for Losses/Damages

1 Each employee is empowered to resolve member complaints and concerns as they relate to the Corporation's inability to meet that member's specific needs

2 Should the Corporation fail to ***properly*** meet the needs of its consumers, settlement is in order These are cases in which the Corporation agreed to meet a consumer's request and failed to do so

3 Each employee may, at their sole discretion, expend up to $200 00 per member, per complaint, to resolve such complaint.

4 Each employee must document the circumstances surrounding the issue and request that the member provide proper documentation in support of their complaint (See attached Exhibit "A")

5 Should a member make additional claims within a twelve (12) month period, resolution of the additional claim(s) must be approved by the Department Manager **and** the General Manager

6 This policy is not intended to allow members to avoid ***necessary and reasonable*** charges (e g , service charges, deposits, fees, etc), but to make the member "whole" relative to his losses (e g damaged equipment, damaged yard, loss of food due to our equipment failure, etc)

B Service Guarantee

Each employee is empowered to meet the needs of the members The promptness of our actions and the level of service we provide is a critical element of our relationship with our members

1 *Prompt Service Guarantee* - The Corporation guarantees that electric service to a newly constructed residential home site, where all permits and wiring are in place, will be completed within one (1) day of the tentatively scheduled completion date This excludes major developments such as subdivisions, industrial parks, shopping centers, and other similar projects If this guarantee for completion of service is not met, the Cooperative will pay the customer an amount equaling $20 as described in this section.

2 *Accurate Meter Reading Guarantee* - The Corporation guarantees accurate meter reading when the consumer's meter is read by a member of its staff If this guarantee for accurate meter reading is not met, the Cooperative will pay the customer an amount equaling $20 as described in this section.

III RESPONSIBILITY

It shall be the responsibility of each and every employee to administer this policy It shall be the responsibility of each Department Manager to see that each and every member contact is handled as outlined It shall be the responsibility of the General Manager to develop appropriate controls for the overall enforcement of this policy and to report his findings to the Board of Directors

ADOPTED	December 7, 1995	EFFECTIVE	December 7, 1995
REVISED	July 18, 1996 October 17, 1996 December 27, 1996	EFFECTIVE	October 15, 1996 December 15, 1996 January 1, 1997

SAWNEE ELECTRIC MEMBERSHIP CORPORATION
POLICY NO. 411, CUSTOMER SERVICE

EXHIBIT "A"

Member Name _____ Account No _____

Address _____ Member No _____

_____ Phone No _____

City _____ State _____ Zip Code _____

Description of problem/complaint _____

_____

_____

_____

_____

_____

_____

_____

_____

_____

_____

Value of Settlement $_____

Employee's Signature _____ Date ___/___/___

Department Manager _____ Date ___/___/___

(If Required)

General Manager _____ Date ___/___/___

NOTE All necessary documentation in support of this settlement should be attached to this exhibit form.

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

POLICY NO 411
CUSTOMER SERVICE

	Sample of Items to be Considered for Reimbursement		Sample of Items NOT to be Considered for Reimbursement
1	Hotel Bill (Consumer moving Promised power on a specific date, did not complete Consumer had to stay in hotel)	1	Service Charges
2	Loss of food in freezer or other losses (Consumer's power was disconnected by mistake)	2	Deposits
3	Losses/damages associated with Sawnee's failure to disconnect power on date requested	3	Other fees
4	Damage to appliances/equipment or loss of food in freezer, etc due to Sawnee's equipment failure (power surge, brownout, etc)	4	Losses which occurred through NO FAULT of Sawnee EMC (inclement weather conditions or other acts of God, acts from individuals outside the Corporation, etc)
5	Damage to driveways		
6	Damage to yards or lawns		
7	Damage to mailboxes		
8	Damage of property from "failure to locate"		
9	Consumer unhappy with right-of-way clearing		
10	Damage to "favorite tree/shrub" Wants replacement		
11	Had to take pet to vet (Sawnee's employee sprayed animal with mace)		
12	Lost time from work (Customer had appointment with engineer, energy audit, load management installation, etc - employee never showed up for appointment)		
13	Sawnee used wrong meter multiplier causing overpayment of bills		
14	Meter was misread causing overpayment of bill		

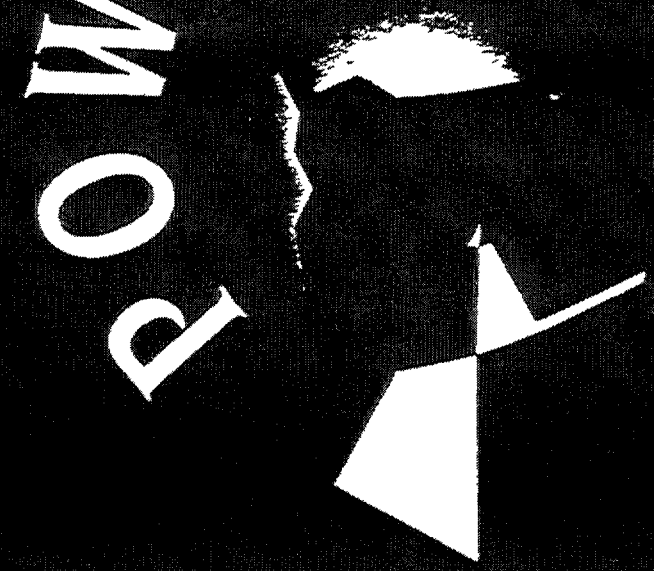
SUPPORTING

REFERENCE

MATERIAL

Electric Utility Knowledge Handbook

POWER•UP



Putting Customers First

HOUSTON LIGHTING & POWER COMPANY

Acknowledgement

We would like to thank the following people who contributed their time and effort to the successful completion of Power Up! Electric Utility Knowledge

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Putting Customers First

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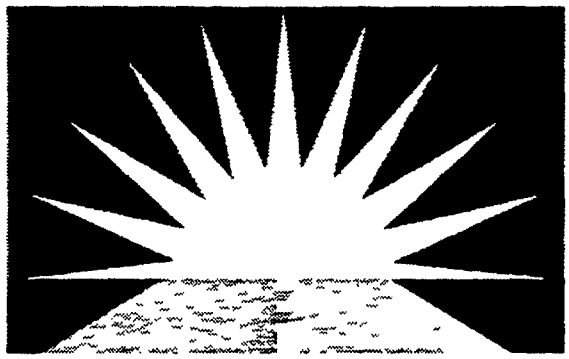
SERVICE FIRST

Houston Lighting & Power Company (HL&P) is engaged in the generation, transmission, distribution, and sale of electric energy, serving a 5,000 square-mile area of the Texas Gulf Coast Region HL&P has served this area for more than 100 years and our "Service First" motto defines the commitment we pledge to our customers

Today, profound and fundamental change is sweeping across the electric utility industry New technologies, competitive forces and regulatory approaches are combining to exert tremendous pressure to restructure our industry

HL&P is ready for this changing environment and will continue to respond quickly to both new threats and new opportunities in the energy market HL&P is committed to doing everything we can to ensure customer loyalty and our **Vision 2000** reflects this commitment

VISION 2000



HL&P will be the provider of choice for energy and energy services by meeting customer expectations at a competitive price.

To ensure this vision becomes a reality, we must all work together to make sure that our "Service First" motto is never compromised Customer loyalty is no longer guaranteed by being the only game in town To earn customer loyalty, we have to treat each person served as an individual

...We have to put customers first!

TYPES OF CUSTOMERS

Customers are grouped into "types" as a means of distinguishing customers with similar end uses and/or demands HL&P uses these groupings to track and predict the costs of serving various customer classes

HL&P's main customer groupings include residential, commercial, industrial municipal, and public utilities

Residential customers use electricity for heating, cooling household appliances, and lighting in a private dwelling setting (home or apartment)

Commercial and *industrial* customers use electricity for heating, cooling, appliances and industrial equipment in settings ranging from small retail stores to large industrial plants and high-rise office buildings

Municipal customers are *city* accounts These customers use electricity for street lights

Commercial, industrial, and municipal customers are all referred to as *retail customers* because they use the electricity they purchase from HL&P themselves

Public utilities purchase electricity from HL&P to sell These customers are referred to as *resale customers* — because they sell the electricity to their own retail customers

As of December 31, 1994

Type of Customer	Number of Customers	% of Total kWh Sales
Residential	1,301,074	28%
Commercial	170,959	22%
Industrial	1,670	48%
Municipal, Public Utilities	92	2%

ESTABLISHMENT OF SERVICE

Electricity is an indispensable part of our daily lives Our customers depend on it for lighting, cooling and heating their homes, and much more HL&P understands this and is committed to providing dependable electric power that meets the present and future requirements of our customers

HL&P's goal is to have customers who incur specific costs pay those costs Therefore, some type of payment guarantee is required of all **new** customers

A new customer is defined as *"Someone who has not had electrical service with HL&P within the last two years"*

Deposits. The most common form of payment guarantee is a deposit equal to one-sixth of the estimated annual billing for the new customer The deposit is due prior to the connection of service

After 12 consecutive months of on-time payments, the deposit plus interest is applied to the customer's bill on the 13th month If a customer terminates service prior to the end of the 12 consecutive months, the deposit plus accrued interest is applied to the final bill (If HL&P owes the customer money after the final bill has been settled, a check is mailed)

The deposit earns interest at the annual rate established by the Public Utility Commission of Texas This interest is based on the average treasury bill rate

Deposit Alternatives. In lieu of a deposit, a guarantor with a good HL&P credit history may co-sign for a new customer

By co-signing, the guarantor agrees to become financially responsible for the account should the account holder fail to make payments Both the new customer and the guarantor must sign a contract before service is connected

HL&P will also consider a letter of credit history from another electric utility or the credit history of a spouse in lieu of a deposit

Suspension of Service

Electrical service may be disconnected for nonpayment of bills HL&P, along with all utilities, is required to follow the appropriate notification procedures outlined by the regulatory authorities before disconnecting a customer's service for nonpayment The notification process requires that customers be given 10-days written notice prior to the disconnection of service The language in the notice is also specified by the regulatory authorities

HL&P's policy is to work with the customer prior to disconnection of their electric service Consideration is given to the customer's previous payment record, age, and the amount of the past due bill

Reconnection of Service

Customers who have had their service suspended for nonpayment of bills must pay the full past due amount, plus any additional deposit that might be required, prior to reconnection of service

Service that has been disconnected can usually be restored the same day if HL&P receives the reconnect order before 6 p m At the time the customer asks for service to be reconnected, a reconnect charge is added to the customer's account

Moving?

HL&P offers a 30-day overlap in service for customers moving to a new residence This overlap enables customers to have electric service at both their old address and their new address during the move process

Customers can notify HL&P of an impending move by telephone or mail To process the request, HL&P will need the following information

(1) Current address of present service connection
(2) HL&P account number
(3) New address where the service is to be connected
(4) New mailing address

Note At the very minimum, customers should notify HL&P 24 hours in advance when moving to a new residence

SPECIAL PROGRAMS AND SERVICES

HL&P's service area covers roughly 5,000 square miles, and serves more than 150 cities, towns, and communities across South Texas To satisfy the needs of such a large and diverse customer base, HL&P offers a number of special programs and services These special programs and services are designed to help customers better manage their electric bills and maintain their service with us

Easy Access Network

The Easy Access Network is a fully automated telephone system designed to provide customers with fast, accurate information about their electric service To reach the Easy Access Network, customers simply dial the local HL&P Customer Service telephone number listed on their bill

Once connected, customers listen to the options available on the instructional menus and make their selections The option to talk personally with a customer service representative is also available And, if all representatives are busy with other customers, an automated voice tells the customer exactly how long they'll have to wait

The Easy Access Network lets customers do everything from getting information about their accounts, to having their present service disconnected, to reporting an outage and dispatching a repair crew to fix the problem

Payment Agency Locations

Customers preferring to pay their bill in person may choose to pay at the HL&P Personal Service Center located at 2102 Austin in Houston, or at more than 100 payment agents (principally grocery stores) throughout the Company's service area

New technology has made it possible for these payment agents to credit bill payments

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directly to customer accounts The payment agents use a laser-scanning "wand" to scan the coded lines on the customer's bill and download the data into HL&P's computer Payments made at any of these payment agents by 7 p m will be posted that night

Note. Customers can also pay past due bills (including partial payments), reconnect charges, and deposits required on new accounts at the payment agent locations

Automatic Payment

The Automatic Payment Program (APP) offers customers a method of paying their electric bills, automatically every month, directly from their financial institutions To participate in the APP, customers must (1) complete and sign an application authorization form, and (2) return the form to HL&P along with a check or deposit slip marked "void" from the financial institution the electric bill is to be paid from

Once the APP is activated, customers continue to receive copies of their monthly electric bill statements If they have any questions concerning the monthly statement, they have four days before the actual due date to contact HL&P Otherwise, the payment amount will be electronically transferred on the statement's due date

Balanced Billing Program

The Balanced Billing Program takes the surprise out of summer electric bills by "balancing" payments over a 12-month period Each "balanced bill" is based on an average of electricity usage during the previous 12 months To determine the average, HL&P totals the kilowatt hours used during the past 11 months, plus the current month's usage, and divides by 12

Meter readers continue to check the customer's meter on a regular basis If at the end of the Balanced Billing program year, the customer's "balanced" payments have been more than the actual cost of usage, the customer receives a credit for overpayment on the 12th installment of the program year If the customer's "balanced" payments have been less than the actual cost of usage, the difference will be adjusted in the final installments of the program year

Balanced Billing is a time-payment plan and, like other credit plans, has some special terms and conditions

- If, twice during the program year, payments are not received by the date shown on the statement, the customer is returned to normal billing.
- If the customer is moving to a new address and wants Balanced Billing

for the new address the final balance due for the old account must be paid-in-full before the customer can be placed back on the program

- If a customer discontinues participation in the program at any time during the program year, there is at least a one-year waiting period before they may join again

Double Notice Protection Plan

The Double Notice Protection Plan is designed for customers who may overlook their electric bill unintentionally

This program allows customers to designate a specific person or agency to receive duplicate copies of the monthly electric bill or any "past due" notices The designated person or agency is not responsible for payment, but may be able to assist the customer in various ways to prevent interruption in service This plan can be a valuable service for

- Senior customers who may not be able to handle personal affairs as well as they once did
- Customers who are ill and might overlook bill payments
- Frequent travelers who are often away when electric bills are due

Senior Citizen Convenient Payment Plan

The Senior Citizen Convenient Payment Plan is designed to help seniors adapt to a fixed income This plan adjusts the payment due date to coincide with the arrival of Social Security or retirement checks To qualify for the Senior Citizen Convenient Payment Plan

- A customer must be at least 62 years old and must have filed for Social Security, civil service, teacher or railroad benefits, or pensions
- Electrical service must be listed in the senior citizen's name
- The customer's present HL&P account must be current, with no overdue balance
- The normal due date on the customer's electric bill must fall between the 23rd of one month and the 10th of the following month (*Note:* If the due date on the customer's electric bill falls on any other day of the month, the customer's Social Security or retirement checks and electric bill should already coincide)

When the customer joins the plan, the new due date of their electric bill will become the 10th of each month

Only the due date of the electric bill will change HL&P will continue to read the customer's meter at the same time each month, and the electric bill will arrive at its usual time

THE SHARE PROGRAM

SHARE is an energy-assistance program designed to help elderly and disabled residents living on a low, fixed income pay their electric bills This program is supported by contributions from our customers plus funds from our shareholders

All SHARE contributions are turned over to designated non-profit social service agencies within HL&P's service area These agencies administer and disburse the SHARE funds to qualified participants based on individual need

Customers can apply for SHARE funds by contacting a SHARE agency (Call HL&P for a list of these agencies) Applicants must submit proper identification, proof of age, and verification of their status from Social Security

Since its implementation in 1983, the SHARE program has helped thousands of HL&P customers maintain their electric service

THE GATEKEEPER PROGRAM

The Gatekeeper Program is a community-wide effort to help senior citizens in our service area when they are in need or distress

Thousands of HL&P employees, police officers, and city workers have been designated "Gatekeepers " These Gatekeepers are often in daily contact with area residents and are trained to recognize the needs of seniors, particularly those living alone

Should these Gatekeepers notice anything out of the ordinary at a senior's home, they call a Gatekeeper Hotline The call is then referred to a social service agency for further investigation

MARKETING AND INDUSTRIAL RELATIONS

A Transition to Competition

For the last four years, HL&P's marketing activities have focused on Demand-Side Management (DSM) strategies to reduce "peak" demand and allow for a more efficient use of available generating resources These strategies have included the development, implementation, and monitoring of conservation, energy efficiency, and load management programs to influence the level or timing of customers energy use

In the new environment of competitive energy sales and services, HL&P's residential, commercial, and industrial marketing efforts are shifting away from regulatory-driven DSM toward market-driven and customer-oriented initiatives With diminished capacity value, typical quantitative utility goals of participation and impact are less important and goals of greater customer satisfaction, loyalty, revenue growth and profitability take top priority

To smoothly transition from traditional conservation and load management to sales and energy services, existing DSM programs have been modified and supplemented with new competitive directives to achieve three fundamental keys to future marketing success

- Grow new revenues through increased kWh sales and through the sale of new products and services
- Retain at-risk revenues
- Position HL&P as the supplier of choice

New Products and Services

In the Marketing Department, a significant portion of new product development efforts are aimed at promoting electro-technologies to key market segments in the large commercial and industrial sector and the introduction of expanded energy services across all market sectors Promising

electrotechnologi include electric motors for gas compression stations, industrial process heat pumps and disinfection (ozonation) of municipal waste water effluent Commercial and residential audits, traditional DSM activities, provide opportunities to introduce customers to HL&P's proposed fee-based energy services offerings such as power quality improvements, turnkey performance contracting, central plant operations, and residential appliance protection and repair

In 1995, many of these new products and services were selectively applied to the marketplace in response to Request for Proposals from customers for energy services One of the early Marketing successes involved fee-based operational audits for 21 Houston Independent School District facilities However, full scale implementation of most of Marketing's new product and service offerings is not expected until 1996

Marketing's current economic development efforts are expanding to attract targeted industry segments that complement businesses currently in the service area, specifically the chemical industry and national markets Growing these market segments will significantly impact HL&P's future profitability

Retain Revenues

Competitive pricing issues and federal policies barring the production of chlorofluorocarbons (CFC) refrigerants have placed the future revenues of several industrial and large commercial customers at risk to non-electric alternatives Market-based pricing initiatives such as the SCP (Special Contract Pricing) tariff and technical support and analyses are some of the tools devised by Marketing to retain at risk industrials For commercial cooling threats from gas-driven chillers Commercial Cool Storage, a highly successful DSM program has been transformed into a competitive service offering to provide customers with an alternative pricing option and a means to recover capital costs associated with CFC compliance In addition to Commercial Cool Storage, development is underway on a fully integrated chil ervices program for customers most susceptible to the installation of gas cooling Together these programs should prove successful in allowing HL&P to maintain its 95% share of the commercial cooling market

Supplier of Choice

Four years of Demand-Side Management has produced benefits consistent with the marketing objective of satisfying customer needs As the cornerstones of our "branding" efforts, many of HL&P's traditional DSM programs are being transformed to build more positive perceptions of the customer/utility relationship and the value of products and

services supplied by HL&P Perceptions are important! Before customers will select HL&P as their supplier of non-traditional electric services HL&P must be their first choice as supplier of electricity

Here's what is in-store for some of Marketing's most visible DSM programs

Good Cents New Home — Designed to improve thermal and structural construction standards in the new home market, Good Cents will quickly move to an information-based activity with a value message aimed at a broader audience than the traditional new home buyer Behind the value message is a constant reminder to consumers that HL&P is the exclusive promoter of home energy efficiency With the new Good Cents strategy, HL&P will have a higher profile, lower cost program that uses the consumer goodwill to create more sales opportunities for new end-use products and services

Good Cents Apartment — This program will be transformed into a load retention tool to combat gas threats in the multi-family residential market

EEHVAC Retrofit Program — Like Good Cents this long-standing DSM program will transition to an information-based activity and shift away from incentives in favor of financing and for-fee heat pump and air conditioning dealer referrals The EEHVAC program represents HL&P's best opportunity to grow revenue and retain cooling load in the residential market

*EIC Customer Outreach, Energy Efficient Appliance, Energy*Efficiency*Environment* — These programs will be collapsed into a single comprehensive activity to promote electrotechnologies and new products and services to the residential market

Energy Check-Up — This home audit service builds positive customer perceptions and will open the door to the future sale of HL&P products and services

Pool Pump — Same strategic attributes as Energy Check-Up

Energy Partners — A valuable resource option, Energy Partners will go into a maintenance mode of 1,000 net switches per year beginning in 1996 Program participants will remain the focus of an aggressive communications effort to sell new products and services

Energy Manager — Customers want greater control over the price and the amount of electricity they use in their homes Energy Manager technology allows customers to adjust energy use according to pricing signals received from HL&P The pricing signals are based on current generating costs

The Future Is Now

For 60% of our customers, the only contact they have with HL&P is through their bill or to report an outage — both have negative implications for future business dealings in the open marketplace

Leveraging existing DSM programs adding value through new products and services and exceeding customer expectations are milestones to meeting the objectives of the three keys to marketing success and ultimately the "branding" of HL&P for future prosperity

ELECTRICITY THEFT

Every day, the Company suffers the loss of revenue from the sale of electricity as a result of customers bypassing or tampering with their electric meters These losses are at the expense of other customers and contribute to increases in utility bills

Bypassing electric meters or meter tampering is recognized under Texas law as Theft of Electricity It is a criminal offense and classified as a third-degree felony In certain instances the Company has pursued criminal charges against individuals who are caught bypassing or tampering with their electric meters

In addition to the losses suffered by the Company, bypassing and meter tampering are dangerous activities and can result in fires or electrocution There are safeguards built into the meter configuration and when someone bypasses a meter they bypass all the safeguards built into the system

The Company has several methods of detecting bypasses and meter tampering The majority of instances are reported by field personnel or are detected by a special computer program that flags accounts with suspicious, uncommon patterns of electricity usage Instances are also anonymously reported to HL&P by cautious neighbors, friends, and relatives of those involved in or benefiting from bypasses or meter tampering

ELECTRICAL SAFETY

Most people think injuries happen by chance or "accident" — a word that implies something that can't be foreseen or avoided But electrical injuries typically can be both foreseen and avoided **Understanding electricity helps prevent electrical injuries.**

Inside and outside the home, at work and at play, electricity waits to leap into action at the flick of a switch Because electricity is everywhere, it's important to know how to guard against its potential dangers in many different situations

HL&P's commitment to safety is paramount We believe that educating the public plays a vital role in promoting safety within our service area The Company takes every opportunity to communicate the importance of attention to electrical safety Our speakers bureau actively promotes this topic to civic groups and schools And we regularly remind customers through print television and radio advertising of the need to live work, and play around electricity safely

OUTDOOR DIGGING

Remember some power lines have been installed underground Cutting into an underground power line can result in electrocution or serious injury

Before you begin any outdoor projects take a few minutes to make sure you are not going to encounter any underground utility lines Look overhead for power lines running from HL&P's distribution line to your house If you don t spot one, chances are your home is serviced by an underground electric line

HL&P is a founder and corporate member of the Utility Coordinating Committee (UCC) This committee maintains a Call Before You Dig one-call program (1-800-669-8344) to arrange for underground utilities to be staked before digging begins

In addition to our activities through the UCC, HL&P's Public Safety Department makes presentations to companies which are involved in construction or excavation

DAY 2

8 30 - 10 15	Distribution Company Support Services Human Resources Information Services Buildings and Grounds Fleet Management	Mr Billy Ussery
10 15 - 10 30	Break	
10 30 - 12 00	Distribution Company Support Services Engineering Field Operations General Operations and Maintenance System Planning	Mr Billy Ussery
12 00 - 1 00	Lunch	
1 00 - 2 00	Financial Planning Finance and Accounting Rate Making Planning and Budgeting	Mr Billy Ussery
2 00 - 3 00	Materials Purchasing and Management	Mr Billy Ussery
3 00 - 3 15	Break	
3 15 - 5 00	Governmental Relations	Mr Billy Ussery

DISTRIBUTION

COMPANY

SUPPORT SERVICES

DISTRIBUTION COMPANY SUPPORT SERVICES

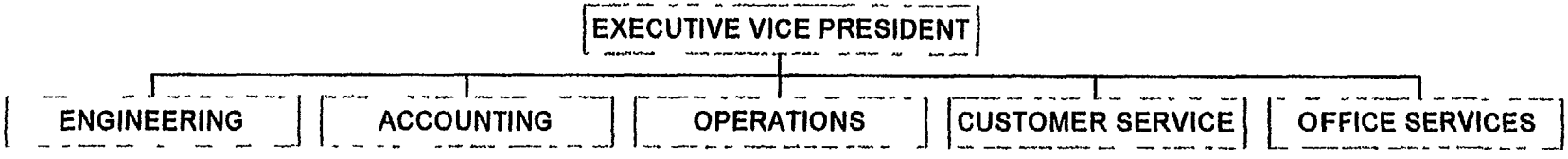
ORGANIZATIONAL STRUCTURE

OVERVIEW FOR DAY 2

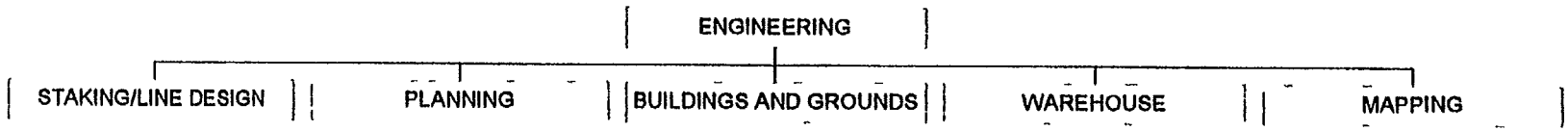
- MORNING
  - CORPORATE STRUCTURE
  - GENERAL RESPONSIBILITIES OF DIFFERENT SECTIONS
- AFTERNOON
  - FINANCIAL PLANNING
  - MATERIALS PURCHASING
  - GOVERNMENTAL RELATIONS

ORGANIZATIONAL STRUCTURE

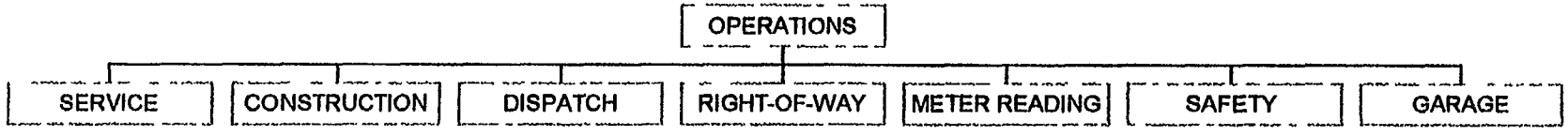
A TYPICAL ORGANIZATIONAL STRUCTURE



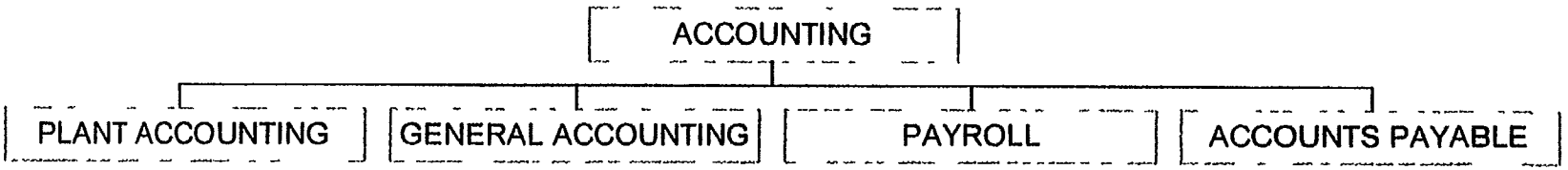
ENGINEERING



OPERATIONS


OPERATIONS
SERVICE
CONSTRUCTION
DISPATCH
RIGHT-OF-WAY
METER READING
SAFETY
GARAGE

ACCOUNTING



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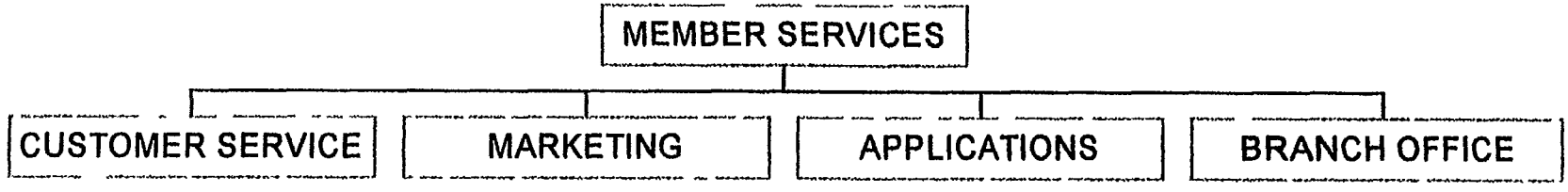
MEMBER SERVICES



OFFICE SERVICES

ENGINEERING

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- New Service Requests
- Line Modifications
- Line Relocations
- System Improvement Projects
- Special Equipment
- General System Maintenance
- Design Questions
- New Developments
- Trouble Shooting
- Substations

PLANNING

- Two Year Work Plan
- Long Range Plan
- Outage Analysis
- Load Forecast
- Internal SCADA Maintenance
- New Development Coordination and Design
- Power Quality
- Historical Database Upkeep and Maintenance

BUILDINGS AND GROUNDS

- General Building Maintenance
- Grounds Maintenance
- Internal Electrical Maintenance
- Landscaping
- ETC
- ETC
- ETC

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- Inventory
- Purchasing
- Material Issues and Returns
- Loan Employee and Contractor

MAPPING

- Maintenance and Upkeep of Mapping System
- Minimal Database Maintenance
- Inner Office Type Staking of New Jobs
- Subdivision Design

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- Overview of Other Activities Within the Engineering Department
  - Contractors
  - Contract Administration
  - Availability
  - Easement Disputes
  - Other

OPERATIONS

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- Disconnects
- Reconnects
- Meter Reads
- Power Quality Inspections
- Load Management Installation
- SCADA

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- New Job Construction
- Installation of New Facilities
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- Dispatching of Crews for Daily Work
- Dispatching of Crews for Outage Restoration

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- Damage Repair
- Miscellaneous Consumer Complaints

METER READING

- Reading Meters
- Read Outs

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- Maintenance of Fleet
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- Control of Fuel System and Regulations

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- Crew Operations
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- State Regulations
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OPERATIONS

- Overview Of Operations
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  - C vs
  - Outage Restoration

ACCOUNTING

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- Work Orders
- Continuing Property Records
- Monitoring Material Inventory Activities
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- Financial Support Documents

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- Miscellaneous Invoicing
- Property Damage Claims
- Monthly Journal Entries
- General Ledger
- Financial Statements
- Tax Reports
- Cash Reconciliation
- Debt Service
- Continuing Property Records for General Plant

PAYROLL

- Payroll
- Employee Master Files
- Time Posting
- Earnings
- Deductions
- Payroll Taxes
- Annual Leave Records

ACCOUNTS PAYABLE

- Bill Payment
- Purchase Orders
- Receiving Ticket Reconciliation
- Account Distributions

ACCOUNTING

- Overview
  - Expense Budgeting / Monitoring
  - Financial Forecast
  - Capital Budget
  - Loan Document Support
  - Annual Financial Audit

MEMBER SERVICES

CUSTOMER SERVICE

- New Service Applications
- Outage Calls
- Consumer Complaints
- Call Center Type Operation

MARKETING

- Residential
- Commercial
- Customer Choice
- Energy Management/ Conservation
- Special Functions
  - Newsletter
  - Annual Meeting
  - District Meeting

APPLICATIONS

- Similar to Customer Service
- Walk-In Applications
- Outage Calls

BRANCH OFFICE

- Payment Center
- Applications for Service
- General Requests

MEMBER SERVICES

- Overview
  - Customer Complaint Center
  - Outage Calls
  - Hours of Operation

OFFICE SERVICES

DATA PROCESSING

- Maintenance of Existing Software
- New Software Development
- Maintenance and Upkeep of Computer System Network
- Reports
- Bills

HUMAN RESOURCES

- Employee Applications
- Employee Policies
- Insurance and Benefits for Employees
- Damage Claims

COLLECTIONS

- Bill Payment Arrangements
- Billing Complaints

BILLING

- Energy Billing
- Bill Disputes
- Billing Questions

ACCOUNTS RECEIVABLE

- Payment Processing
- Drive-In Window
- Walk In Payments

OFFICE SERVICES

- Overview
  - General Questions
  - Affirmative Action

FINANCIAL PLANNING

DAY 2 - AFTERNOON SESSION

OVERVIEW

- Financial Planning
  - Finance and Accounting
  - Rate Making
  - Planning and Budgeting

- Materials and Purchasing
- Governmental Relations

FINANCIAL PLANNING

- "One of those Accounting Things"

FINANCIAL PLANNING

- Extremely Important
- Goes Hand In Hand with System Planning
- Projected Revenues Versus Expenses
- Must Meet Certain Financial Objectives
- Mortgage Requirements

FINANCIAL PLANNING TOOLS

- Financial Forecast
- Load Forecast
- Expense Budget
- Capital Budget
- Work Plan
- Long Range Plan

IMPORTANT FACTORS

- Accurate Historical Data
- Reasonable Projections
- Large Projects
- Major "One Time" Projects

FINANCIAL PLANNING

- Examples of Financial and Statistical Report - Form 7
  - Statement of Operations
  - Balance Sheet
  - Changes In Utility Plant
  - Power Requirements Database

Public reporting burden for this collection of information is estimated to average 17 hours per response, including the time for reviewing instructions, searching existing data sources gathering and maintaining the data needed, and completing and reviewing the collection of information Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Department of Agriculture Clearance Officer OIRM, AG Box 7630 Washington DC 20250 and to the Office of Management and Budget, Paperwork Reduction Project (OMB #0572-0032) Washington, DC 20503 OMB FORM NO 0572-0032, Expires 06/30/98

This data will be used by RUS to review your financial situation. Your response is required (7 U.S.C.901 et seq) and is not confidential

USDA-RUS

FINANCIAL AND STATISTICAL REPORT

BORROWER DESIGNATION
GA077

BORROWER NAME AND ADDRESS
SAWNEE ELEC MEMB CORP
PO BOX 266
CUMMING GA 30128-0000

INSTRUCTIONS - *Submit an original and two copies to RUS Round all amounts to nearest dollar For detailed instructions see RUS Bulletin 1717B 2*

PERIOD ENDED
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RUS USE ONLY

CERTIFICATION

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII RUS WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES

Cynthia L Anderson — SIGNATURE OF OFFICE MANAGER OR ACCOUNTANT — DATE 1/21/97

Michael A Brooks — SIGNATURE OF MANAGER — DATE 1/21/97

PART A STATEMENT OF OPERATIONS

ITEM	YEAR TO-DATE LAST YEAR (a)	YEAR TO-DATE THIS YEAR (b)	YEAR TO-DATE BUDGET (c)	THIS MONTH (d)
1 Operating Revenue and Patronage Capital	99 737 867	106 199,605	104,493,574	8,010,380
2 Power Production Expense	0	0	0	0
3 Cost of Purchased Power	71 634,610	72 159,350	73 479 698	6 307 407
4 Transmission Expense	0	0	0	0
5 Distribution Expense - Operation	2,915 383	3 239,644	3 121 393	444,874
6 Distribution Expense - Maintenance	4 301 956	4,770 235	4 896 772	478 990
7 Consumer Accounts Expense	2,303 078	2,530,052	2,408 350	213 968
8 Customer Service and Informational Expense	957 273	908 162	1 019 165	41 619
9 Sales Expense	143 403	135 950	131 863	12 383
10 Administrative and General Expense	4,155 002	4,318 175	4 943 699	418,858
11 Total Operation & Maintenance Expense *(2 thru 10)*	86 410 705	88,061,568	90 000,940	7 918 099
12 Depreciation and Amortization Expense	4,835 543	5,461,439	5 370,235	501,323
13 Tax Expense - Property & Gross Receipts	1,213 037	1,324 056	1 244 158	158 041
14 Tax Expense - Other	715 708	753 040	717 328	63 343
15 Interest on Long-Term Debt	5 084 334	5,767,038	5 964,100	488 646
16 Interest Charged to Construction Credit.	0	0		0
17 Interest Expense - Other	363 070	608 448	370,000	82 803
18 Other Deductions	25 268	23,268	52,000	1 472
19 Total Cost of Electric Service *(11 thru 18)*	98,647,665	101 998 857	103 718 761	9 213 727
20 Patronage Capital & Operating Margins *(1 minus 19)*	1 090 202	4 200 748	774,813	(1 203,347)
21 Non Operating Margins - Interest.	171,728	191 219	210 000	42 651
22 Allowance for Funds Used During Construction	0	0	0	0
23 Income (Loss) from Equity Investments	0	0	0	0
24 Non Operating Margins - Other	(77,940)	(110,034)	0	(76 906)
25 Generation and Transmission Capital Credits	1,523,700	1 493,029	1 544 700	1 492 300
26 Other Capital Credits and Patronage Dividends	307,992	388 957	251 736	0
27 Extraordinary Items	0	0	0	0
28 Patronage Capital or Margins *(20 thru 27)*	3,015 682	6 163,919	2 781 249	254 698

PART B DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR TO DATE LAST YEAR (a)	YEAR TO DATE THIS YEAR (b)	ITEM	YEAR TO-DATE LAST YEAR (a)	YEAR TO-DATE THIS YEAR (b)
1 New Services Connected	5 414	6,077	5 Miles Transmission	0 00	0 00
2 Services Retired	559	754	6 Miles Distribution - Overhead	2 893 53	2 921 75
3 Total Services in Place	71 559	77 703	7 Miles Distribution - Underground	2 498 51	2 877 92
4 Idle Services (Exclude Seasonal)	931	808	8 Total Miles Energized (5 + 6 +7)	5 392 04	5,799 67

This data will be used by RUS to review your financial situation Your response is required (7 U S C 901 et seq) and is not confidential

USDA-RUS

FINANCIAL AND STATISTICAL REPORT

INSTRUCTIONS *See RUS Bulletin 1717B 2*

BORROWER DESIGNATION GA077

PERIOD ENDED 1996 Annual

RUS USE ONLY

PART C BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1 Total Utility Plant in Service	188 695,643	30 Memberships	329 340
2 Construction Work in Progress	1,528,311	31 Patronage Capital	57 644,159
3 Total Utility Plant *(1+2)*	190,223,954	32 Operating Margins - Prior Years	(638,729)
4 Accum Provision for Depreciation and Amort	24 634,660	33 Operating Margins Current Year	6 082 735
5 Net Utility Plant *(3-4)*	165 589,294	34 Non-Operating Margins	81 184
6 Non-Utility Property (Net)	0	35 Other Margins and Equities	632 948
7 Investments in Subsidiary Companies	0	36 Total Margins & Equities *(30 thru 35)*	64 131,637
8 Invest. In Assoc. Org - Patronage Capital	20,686,788	37 Long-Term Debt - RUS - Econ Devel (Net)	69,596,056
9 Invest. In Assoc Org - Other - General Funds	0	(Payments-Unapplied $ 0)	
10 Invest. In Assoc Org - Oth - Nongen Funds	2 678,133	38 Long-Term Debt - RUS - Econ Devel (Net)	0
11 Investments in Economic Development Projects	0	39 Long-Term Debt - Other - REA Guaranteed	0
12 Other Investments	0	40 Long-Term Debt - Other (Net)	49 050,031
13 Special Funds	1 289 000	41 Total Long-Term Debt *(37 thru 40)*	118 646,087
14 Total Other Property and Investments *(6 thru 13)*	24 653,921	42 Obligations Under Capital Leases - Noncurrent	0
15 Cash - General Funds	2,151,801	43 Accumulated Operating Provisions	2 274,800
6 Cash - Construction Funds - Trustee	10,541	44 Total Other Noncurrent Liabilities *(42+43)*	2,274,800
17 Special Deposits	0	45 Notes Payable	1,879 487
8 Temporary Investments	0	46 Accounts Payable	7,573,123
19 Notes Receivable (Net)	0	47 Consumers Deposits	974 868
20 Accounts Receivable - Sales of Energy (Net)	5,331,887	48 Other Current and Accrued Liabilities	3 526,215
21 Accounts Receivable - Other (Net)	421,415	49 Total Current & Accrued Liabilities *(45 thru 48)*	13,953,693
		50 Deferred Credits	1,613,167
22 Materials and Supplies Electric and Other	1,429 327	51 Accumulated Deferred Income Taxes	0
23 Prepayments	232,237	52 Total Liabilities and Other Credits	
24 Other Current and Accrued Assets	45 412	*(36+41+49 thru 51)*	200 619,384
25 Total Current and Accrued Assets *(15 thru 24)*	9 622,620	**ESTIMATED CONTRIBUTIONS IN AID OF CONSTRUCTION**	
26 Regulatory Assets	0		
27 Other Deferred Debits	753,549	53 Balance Beginning of Year	0
28 Accumulated Deferred Income Taxes	0	54 Amounts Received This Year (Net)	0
29 Total Assets and Other Debits *(5+14+25 thru 28)*	200,619 384	55 Total Contributions in Aid of Construction	0

PART D NOTES TO FINANCIAL STATEMENTS

THIS SPACE IS PROVIDED FOR IMPORTANT DISCLOSURE NOTES TO THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT
PEPORT ITEMS CONTAINED IN THE INSTRUCTIONS AND ADDITIONAL MATERIAL ITEMS

(A SEPERATE SHEET MAY BE USED IF ADDITIONAL SPACE IS NEEDED)

1) Sawnee EMC received the following cash payments from the retirement of patronage capital from these lenders (associated organizations) for credit

NRUCFC	$228 496 48
GRESCO	87 280 88
SEDC	130 00
TOTAL	$315 907 36

(2) OTIER $10 283 693 57 / 5 767 037 90 = 1 78

(3) ODSC $15 745 132 92 / 7 459,161 31 = 2 11

(4) NOTE RE PART E - The "Balance Beginning of Year" for Acct 397 Communication Equipment and Acct 107 Construction Work in Progress has been modified from the 1995 Form 7 by $74 963 20 and ($74 963 20) respectively This was due to Acct 104 Leased Radio Equipment being misclassifed last year as Work in

1.86

This data will be used by RUS to review your financial situation Your response is required (7 U S C 901 et seq) and is not confidential

USDA-RUS

FINANCIAL AND STATISTICAL REPORT

INSTRUCTIONS See RUS Bulletin 1717B 2

BORROWER DESIGNATION	
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PART D NOTES TO FINANCIAL STATEMENTS

THIS SPACE IS PROVIDED FOR IMPORTANT DISCLOSURE NOTES TO THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT PEPORT ITEMS CONTAINED IN THE INSTRUCTIONS AND ADDITIONAL MATERIAL ITEMS

(A SEPERATE SHEET MAY BE USED IF ADDITIONAL SPACE IS NEEDED)

Progress Our auditors LeRoy & Cole CPAs reclassified this account to Communications Equipment in their financial statements for year ending 12/31/95

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FINANCIAL AND STATISTICAL REPORT

This data will be used to determine your operating results and financial situation Your response is required (7 U S C 901 et seq) and is not confidential

BORROWER DESIGNATION
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INSTRUCTIONS *Submit an original and two copies to RUS*
For detailed instructions see RUS Bulletin 1717B 3

YEAR ENDING
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PART E CHANGES IN UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)	DEPRECIATION RATE (f)
1 Land and Land Rights *(360)*	28 587	0	0	0	28 587	
2 Structures and Improvements *(361)*	0	0	0	0	0	0 00 %
3 Station Equipment *(362)*	6 452 511	1 339 233	101,352	(493 728)	7 196 664	3 09 %
4 Storage Battery Equipment *(363)*	0	0	0	0	0	0 00 %
5 Poles Towers and Fixtures *(364)*	15 282 720	1 879 080	513 487	0	16 648 313	3 09 %
6 Overhead Conductors and Devices *(365)*	23 112 094	2 821 821	968 399	288,252	25 253 768	3 09 %
7 Underground Conduit *(366)*	0	0	0	0	0	0 00 %
8 Underground Conductor & Devices *(367)*	34 126 246	7 917 831	622,289	0	41 421 788	3 09 %
9 Line Transformers *(368)*	31 931 883	5 311 968	485 051	205 476	36 964 276	3 09 %
10 Services *(369)*	24 072 691	3 950 106	171 115	0	27 851 682	3 09 %
11 Meters *(370)*	7 587 260	1 627 528	0	0	9 214 788	3 09 %
12 Installation on Consumers Premises *371)*	3 222 584	34 305	0	0	3 256 889	3 09 %
13 Leased Prop on Consumers Premises *(372)*	0	0	0	0	0	0 00 %
14 Street Lighting *(373)*	4 037 474	398 270	167 389	0	4 268 355	3 09 %
15 SUBTOTAL Distribution *(1 thru 14)*	149 854 050	25 280 142	3 029 082	0	172 105 110	
16 Land and Land Rights *(389)*	522 490	0	0	0	522 490	
17 Structures and Improvements *(390)*	7 256 103	4 789	0	0	7,260 892	2 00 %
18 Office Furniture & Equipment *(391)*	1 826 221	408 729	233 046	(134 943)	1 866 961	10.21 %
19 Transportation Equipment *(392)*	3 673 225	610 638	163 613	0	4 120 250	8 61 %
20 Stores Tools Shop Garage and Laboratory Equipment *(393 394 395)*	565 898	99 633	9 755	125 558	781 334	6 00 %
21 Power Operated Equipment *(396)*	719 974	0	0	0	719 974	6 00 %
22 Communication Equipment *(397)*	987 391	308 380	0	9 385	1 305 156	8 00 %
23 Miscellaneous Equipment *(398)*	15 452	0	1 976	0	13 476	6 00 %
24 Other Tangible Property *(399)*	0	0	0	0	0	0 00 %
25 SUBTOTAL General Plant *(16 thru 24)*	15 566 754	1 432 169	408 390	0	16 590 533	
26 Intangibles *(301 302, 303)*	0	0	0	0	0	
27 Land and Land Rights Roads and Trails *(350 359)*	0	0	0	0	0	
28 Structures and Improvements *(352)*	0	0	0	0	0	0 00 %
29 Station Equipment *(353)*	0	0	0	0	0	0 00 %
30 Towers and Fixtures and Poles and Fixtures *(354 355)*	0	0	0	0	0	0 00 %
31 Overhead Conductors & Devices *(356)*	0	0	0	0	0	0 00 %
32 Underground Conduit *(357)*	0	0	0	0	0	0 00 %
33 Underground Conductors and Devices *(358)*	0	0	0	0	0	0 00 %
34 SUBTOTAL Transmission Plant *(27 thru 33)*	0	0	0	0	0	
35 Production Plant Steam *(310 thru 316)*	0	0	0	0	0	
36 Production Plant Nuclear *(320 thru 325)*	0	0	0	0	0	
37 Production Plant Hydro *(330 thru 336)*	0	0	0	0	0	
38 Production Plant - Other *(340 thru 346)*	0	0	0	0	0	
39 All Other Utility Plant *(102 104-106 114 118)*	0	0	0	0	0	
40 SUBTOTAL *(15 + 25 + 26 + 34 + 35 thru 39)*	165 420 804	26 712 311	3 437 472	0	188 695 643	
41 Construction Work in Progress *(107)*	2 245 069	(716 758)			1 528 311	
42 TOTAL UTILITY PLANT *(40 + 41)*	167 665 873	25 995 553	3 437 472	0	190 223 954	

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( )A - RUS

FINANCIAL AND STATISTICAL REPORT

INSTRUCTIONS See RUS B m 1717B-3

BORROWER DESIGNATION	RUS USE ONLY
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PAR NALYSIS OF ACCUMULATED PROVISIONS FOR DEPRECIATION - TOTAL ELECTRIC PLANT

ITEM	DISTRIBUTION PLANT (a)	GENERAL PLANT (b)	TRANSMISSION PLANT (c)	OTHER PLANT (d)
1 Balance Beginning of Year	17,517 201	5 154 060	0	0
2 Additions Depreciation Accruals Charged to				
a Depreciation Expense	4 967 160	494 279	0	0
b anning Accounts and Others ..	0	340,378	0	0
c. ubtotal (a + b)	4,967,160	834,657	0	0
3 ess Plant Retirements				
a Plant Retired	2,973,606	274,392	0	0
b Removal Codes	1,057 065	0	0	0
c. Subtotal (a + b) ..	4,030,671	274,392	0	0
4 Plus Salvaged Materials ..	431,919	0	0	0
5 TOTAL (2c 3c + 4)	1 368 408	560 265	0	0
6 Other Adjustments - Debit or Credit.	0	0	0	0
7 Balance End of Year (1 + 5 + /- 6)	18,885 609	5 714 325	0	0

PART G MATERIALS AND SUPPLIES

ITEM	BALANCEBEGINNING OF YEAR (a)	PURCHASED (b)	SALVAGED (c)	USED (NET) (d)	SOLD (e)	ADJUSTMENT (f)	BALANCE END OF YEAR (g)
1 Electric	2,058 117	10,851 864	347 802	11,869,709	2 156	(32,426)	1 353,492
2 Other (15 + 15	41 418	126,086	0	85 249	0	(6 420)	75 835

3 Ratio of Inventory Turnover Electric
Item 1d / (1a + 1g) / 2 = 6 9584

4 Inventory - Electric as Percent of Total Utility Plant
1g / Item 42e E X 100 = 0 71

PA H SERVICE INTERRUPTIONS

ITE	AVERAG JRS PER CONSUMER BY CAUSE				TOTAL
	POWER SUPPL. (a)	EXTR E STORM (b)	PREARRANGED (c)	ALL OTHER (d)	(e)
1 Present Year	0 05	0 00	0 03	1 23	1 31
2. Five - Year Average	0 27	1 83	0 02	1 17	3 29

PART I EMPLOYEE - HOUR AND PAYROLL STATISTICS

1 Number of Full Tim ployees	233	4 Payroll Expensed	5,713,719
2. Man Hours Worked egular Time	499 003	5 Payroll Capitalized	2,135,197
3 Man-Hours Worked - Overtime	40,085	6 Payroll Other	1 519 055

PART J PATRONAGE CAPITAL

M	THIS YEAR (a)	CUMULATIVE (b)
1 General Retirement	576,359	5,521 398
2. Special Re ents	152,865	1 011,616
3 Total Retir + 2)	729,224	6 533,014
4 Patronage ned		57,644 159
5 Patronage able		6,163 919

PART K DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1 AMOUNT DUE OVER 60 DAYS $459 794

2. AMOUNT WRITTEN OFF DURING YEAR $297 875

PART L. kWh PURCHASED AND TOTAL COST

ITEM (a)	RUS USE ONLY SUPPLIER CODE (b)	kWh PUCHASED (c)	TOTAL COST (d)	AVERAGE COST PER kWh (cents) (e)	INCLUDED IN TOTAL COST: FUEL COST ADJUSTMENT (f)	INCLUDED IN TOTAL COST: WHEELING AND OTHER CHARGES (or Credits) (g)
OGLETHORPE PWR CO	0	1,297,788 000	71,335 008	5 50	0	0
SOUTHEASTERN PW N	0	31,199,503	824,342	2 64	0	0
	0	0	0	0 00	0	0
	0	0	0	0 00	0	0
Total		328 987 503	72 159 350	5 43	0	0

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USDA - RUS **FINANCIAL AND STATISTICAL REPORT** INSTRUCTIONS See RUS Bulletin 1717B 3	BORROWER DESIGNATION GA077 YEAR ENDING 1996 Annual	RUS USE ONLY –

PART M LONG - TERM LEASES

(If additional space is needed use a seperate sheet.)

LIST BELOW ALL "RESTRICTED PROPERTY" * HELD UNDER LONG TERM" LEASE *(If none state "NONE")*

NAME OF LESSOR (a)	TYPE OF PROPERTY (b)	RENTAL THIS YEAR (c)
1		$ 0
2.		$ 0
3 TOTAL		$ 0

* *RESTRICTED PROPERTY" means all properties other than automobiles trucks trailers tractors other vehicles (including without limitation aircraft and ship) office garage and warehouse space and office equipment (and without limitation computers) LONG TERM means leases having unexpired terms of more than 12 months (taking into account terms of rental at the option of the lessor whether or not such leases have been removed)*

PART N ANNUAL MEETING AND BOARD DATA

1 Date of Last Annual Meeting	2 Total Number of Members	3 Number of Members Present at Meeting	4 Was Quorum Present? Proxy or Mail
10/05/1996	63 100	800	[X] Yes [ ] No
5 Number of Members Voting by Proxy or Mail	**6 Total Number of Board Members**	**7 Total Amount of Fees and Expenses for Board Members**	**8 Does Manager Have Written Contract?**
0	9	$159 253	[ ] Yes [X] No

PART O LONG - TERM DEBT AND SERVICE REQUIREMENTS

ITEM	BALANCE END OF YEAR (a)	BILLED THIS YEAR INTEREST (b)	PRINCIPAL (c)	TOTAL (d)	RUS USE ONLY (e)
1 Rural Utilities Service (Excludes RUS - Economic Development Loans)	70 875 617	3 635 244	1,220 390	4 855 634	
2 National Rural Utilities Cooperative Finance Corporation	49 649 957	2,131 794	471,734	2 603,528	
3 Bank for Cooperatives	0	0	0	0	
4 Federal Financing Bank	0	0	0	0	
5 RUS - Economic Development Loans	0	0	0	0	
6					
7					
8					
9					
0					
2					
3 TOTAL (Sum of 1 thru 12)	120 525 574	5 767 038	1 692 124	7 459 162	

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USDA-RUS

FINANCIAL AND STATISTICAL REPORT

INSTRUCTIONS See RUS Bulletin 1717B-2

BORROWER DESIGNATION: GA077 -

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RUS USE ONLY

PART R POWER REQUIREMENTS DATA BASE

CLASSIFICATION	CONSUMER SALES AND REVENUE DATA	JANUARY (a)	FEBRUARY (b)	MARCH (c)	APRIL (d)	MAY (e)	JUNE (f)
1 Residential Sales (excluding seasonal)	a No Consumers Served	67 007	67 583	68 146	68 834	69 249	69 942
	b kWh Sold	80 642,713	74 591 937	62,731 644	60,186 303	60,245,730	80 927 436
	c. Revenue	6,396 457	6 002 716	5,260 332	5 114 639	5 166,414	6 925,055
2 Residential Sales Seasonal	a No Consumers Served	0	0	0	0	0	0
	b kWh Sold	0	0	0	0	0	0
	c. Revenue	0	0	0	0	0	0
3 Irrigation Sales	a No Consumers Served	12	12	12	12	12	11
	b kWh Sold	33 675	39 384	41 916	44,289	46 624	95 025
	c. Revenue	4 048	5 245	5 413	5 570	5 725	8,834
4 Comm and Ind 1000 kVA or Less	a No Consumers Served	4 636	4,618	4 696	4 804	4 845	4 903
	b kWh Sold	18 936 656	19 075 337	17,258,362	17 779 145	18 822,161	22 250,697
	c. Revenue	1 633 355	1 671,469	1 569 611	1 602,766	1,672,012	1,923 457
5 Comm and Ind Over 1000 kVA	a. No Consumers Served	17	17	16	17	17	17
	b kWh Sold	6 078 760	6 589 909	6,369 953	6 583 603	6 452 978	6 539 154
	c. Revenue	289 701	330 444	324 374	331 135	330 368	331 639
6 Public Street and Highway Lighting	a. No Consumers Served	1 401	1 421	1 416	1 382	1 407	1 435
	b kWh Sold	753 644	770,955	779 542	782,960	815 838	822 674
	c. Revenue	89 901	91 419	92,459	93 280	95 708	100 867
7 Other Sales to Public Auth	a No Consumers Served	70	72	72	109	103	88
	b kWh Sold	266 712	283 971	245 444	302,232	316 302	212 856
	c. Revenue	24 848	25 890	23 660	28 939	29 026	20 439
8 Sales for Resale - RUS Borrowers	a. No Consumers Served	0	0	0	0	0	0
	b kWh Sold	0	0	0	0	0	0
	c. Revenue	0	0	0	0	0	0
9 Sales for Resale - Others	a. No Consumers Served	0	0	0	0	0	0
	b kWh Sold	0	0	0	0	0	0
	c Revenue	0	0	0	0	0	0
10 TOTAL No Consumers (lines 1a 9a)		73 143	73 723	74 358	75 158	75 633	76 396
11 TOTAL kWh Sold (lines 1b 9b)		106 712,160	101 351 493	87 426 861	85 678 532	86 699 633	110 847 842
12 TOTAL Revenue Received From Sales of Electric Energy (lines 1c 9c)		8 438 310	8 127 183	7 275 849	7 176 329	7 299,253	9 310 291
13 Other Electric Revenue		(2 865)	(36 209)	(34 045)	(30 027)	(37,215)	(23 372)
14 kWh - Own Use		475,278	483 740	344 553	297 227	244 604	244 431
15 TOTAL kWh Purchased		108 720 318	95 391 845	95 587 762	81 549 061	114 511 180	133 931 278
16 TOTAL kWh Generated		0	0	0	0	0	0
17 Cost of Purchase and Generation		5 078 000	4 761 250	5 934 723	5 672,677	6 117 094	6 488 017
18 Interchange - kWh - Net		0	0	0	0	0	0
19 Peak - Sum All kW Input (Metered)		238 834	257 633	219 854	197 029	340 006	380 785

[ ] Coincident [X] Non Coincident

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USDA-RUS

FINANCIAL AND STATISTICAL REPORT

INSTRUCTIONS *See RUS Bulletin 1717B-2*

BORROWER DESIGNATION: GA077 –

PERIOD ENDED: 1996 Annual

RUS USE ONLY

PART R POWER REQUIREMENTS DATA BASE *(Continued)*

(SEE PRECEDING PAGE 6 OF RUS FROM 7 FOR HEADINGS OF LINE ITEM NUMBERS BELOW)

LINE ITEM NUMBER		JULY (g)	AUGUST (h)	SEPTEMBER (i)	OCTOBER (j)	NOVEMBER (k)	DECEMBER (l)	TOTAL (Contains a thru l)
1	a	70 385	71 063	71 654	71 869	72 331	72,853	
	b	105 382 902	104 156 880	94 621 141	61 780 989	60 733 527	69 475 306	915 476 508
	c.	9 612,164	9 497 970	8 592,628	5 394 341	4 898 374	5 413 809	78 274 899
2	a	0	0	0	0	0	0	
	b	0	0	0	0	0	0	0
	c.	0	0	0	0	0	0	0
3	a	11	11	11	11	11	11	
	b	103,279	111 798	60 801	59 841	59 459	31 870	727 961
	c.	9 381	9 946	6 566	6,340	6 138	4 754	77,960
4	a	4 911	4 970	5 014	5 055	5 107	5 136	
	b	24 731,211	24 670 222	25 130 861	21 034 921	20 064 542	19 055 350	248 809 465
	c.	2,215 314	2,241 334	2 260 194	1 857,510	1 684 467	1 647 148	21 978,637
5	a	17	18	21	19	19	19	
	b	7 282 369	8 489 774	6 010 371	6 272,210	6 631 048	6 748 600	80 048 729
	c.	355 887	392 695	326,233	331 763	340 113	343 361	4 027 713
6	a.	1 466	1 481	1 505	1 525	1 542	1 568	
	b	858,233	861 056	897,232	866 033	879 570	887 231	9 974 968
	c.	98 398	101 507	104 396	103,570	104 807	105 817	1 182,129
7	a	89	88	117	61	50	50	
	b	257 592	252 893	282 504	198 623	182 501	169 422	2,971 052
	c.	26 072	25 189	27 117	17 311	15 098	15 061	278 650
8	a	0	0	0	0	0	0	
	b	0	0	0	0	0	0	0
	c.	0	0	0	0	0	0	0
9	a	0	0	0	0	0	0	
	b	0	0	0	0	0	0	0
	c.	0	0	0	0	0	0	0
10		76 879	77 631	78 322	78 540	79 060	79 637	
11		138 615 586	138 542 623	127 002 910	90 212 617	88 550 647	96 367 779	1,258 008 683
12		12,317 216	12,268 641	11 317 134	7 710 835	7 048 997	7 529 950	105 819 988
13		(28 492)	(27 272)	(23 705)	74 630	67 760	480 430	379 618
14		271 604	251 163	258 009	229 917	234 693	306 751	3 641 970
15		154 035 826	145 127 183	106 332,872	89 019 070	95 751 396	109 029 712	1 328 987 503
16		0	0	0	0	0	0	0
17		6 777 923	6 515 517	6 238 225	5 882,074	6 386 444	6 307 406	72 159 350
18		0	0	0	0	0	0	0
19		381 937	353 618	328 900	213 519	211 680	258 594	381 937

USDA - RUS

INVESTMENTS, LOAN GUARANTEES AND LOANS - DISTRIBUTION

BORROWER DESIGNATION: GA077

YEAR ENDING: 1996 Annual

RUS USE ONLY

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717 Subpart N identify investments primarily for Rural Development with "RD" in column (e) Both Included and Excluded Investments must be reported See Bulletin 1717B-2 Guide For Preparing Financial and Statistical Reports for complete instructions

PART I INVESTMENTS

DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RD (e)
NON UTILITY PROPERTY (NET)				
a	0	0		
b	0	0		
c	0	0		
d	0	0		
e Totals	0	0		
2 INVESTMENTS IN ASSOCIATED ORGANIZATIONS				
a OGLETHORPE POWER CORPORATION	0	19 229,554	0	
b GRESCO	499 129	0	0	
c NRUCFC	0	956 355	0	
d NRUCFC - CTC s	0	2 677,133	0	
e Totals	500 879	22 864 042	0	
3 INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS				
a	0	0	0	
b	0	0	0	
c	0	0	0	
d	0	0	0	
e Totals	0	0	0	
4 OTHER INVESTMENTS				
a	0	0		
b	0	0		
c	0	0		
d	0	0		
e Totals	0	0		
5 SPECIAL FUNDS				
a NRUCFC MEDIUM TERM NOTES	0	1 289 000		
b	0	0		
c	0	0		
d	0	0		
e Totals	0	1 289 000		
6 CASH GENERAL				
a REGIONS BANK	1 716 997	100 000		
b LANIER BANK	15 634	100 000		
c WACHOVIA BANK	0	2 297		
d ETOWAH BANK	0	38 726		
e Totals	1 782 800	369 001		
7 SPECIAL DEPOSITS				
a	0	0		
b	0	0		
c	0	0		
d	0	0		
e Totals	0	0		

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USDA-RUS **INVESTMENTS, LOAN GUARANTEES AND LOANS** CONTINUATION SHEET	BORROWER DESIGNATION GA077	
	YEAR ENDING 1996 Annual	RUS USE ONLY

INVESTMENTS, LOAN GUARANTEES AND LOANS

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717 Subpart Ndentify investments primarily for Rural Development with RD in column (e)

PART	ITEM	DESCIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RD (e)
I	2	NRUCFC - MEMBERSHIP FEE	0	1,000	0	
I	2	SOUTHEASTERN DATA COOPERATIVE	1 750	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	
I	2	0	0	0	0	

USDA-RUS **INVESTMENTS, LOAN GUARANTEES AND LOANS** CONTINUATION SHEET	BORROWER DESIGNATION GA077	–
	YEAR ENDING 1996 Annual	RUS USE ONLY

INVESTMENTS, LOAN GUARANTEES AND LOANS

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717 Subpart N dentify investments primarily for Rural Development with "RD" in column (e)

PART	ITEM	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RD (e)
I	6	FIRST COMMUNITY BANK	50,169	100,000		
I	6	GEORGIA FIRST BANK		20,086		
I	6	DAWSON COUNTY BANK		5 792		
I	6	SEMC WORKING FUND		2,100		

USDA - RUS

INVESTMENTS, LOAN GUARANTEES AND LOANS - DISTRIBUTION

BORROWER DESIGNATION: GA077 -

YEAR ENDING: 1996 Annual

RUS USE ONLY

PART I INVESTMENTS (Continued)

DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RD (e)
3 TEMPORARY INVESTMENTS				
a	0	0		
b	0	0		
c	0	0		
d	0	0		
e Totals	0	0		
9 ACCOUNTS & NOTES RECEIVABLE (NET)				
a OTHER	421 415	0	(21 028)	
b	0	0	0	
c	0	0	0	
d	0	0	0	
e Totals	421 415	0	(21 028)	
0 COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED				
a	0	0		
b	0	0		
c	0	0		
d	0	0		
e Totals	0	0		
1 TOTAL OF INVESTMENTS (1 thru 10)	2 705 094	24 522 043	(21 028)	

PART II LOAN GUARANTEES

ORGANIZATION (a)	MATURITY DATE (b)	ORIGINAL AMOUNT ($) (c)	LOAN BALANCE ($) (d)	RD (e)
1	0	0	0	
2	0	0	0	
3	0	0	0	
4 TOTALS		0	0	
5 TOTALS (Include Loan Guarantees Only)		0	0	

PART III RATIO

RATIO OF INVESTMENTS AND LOAN GUARANTEES TO UTILITY PLANT [Total of Included Investments (Part I 11b) and Loan Guarantees - Loan Balance (Part II 5d) to Total Utility Plant (Form 7 Part C Line 3)] 1 4200 %

PART IV LOANS

ORGANIZATION (a)	MATURITY DATE (b)	ORIGINAL AMOUNT ($) (c)	LOAN BALANCE ($) (d)	RD (e)
1 Employees Officers Directors	0	0	0	
2 Energy Resource Conservation Loans	0	0	0	
3	0	0	0	
4	0	0	0	
5	0	0	0	
6	0	0	0	
7 TOTALS		0	0	

RATE MAKING - RATE DESIGN

- MANY FACTORS TO CONSIDER
- RATES MUST OBVIOUSLY COVER COSTS PLUS MARGINS
- DESIGNED BASED ON TYPES OF CONSUMERS

RATE MAKING

- Cost of Service Study By Consumer Type
  - Residential
  - Small Commercial
  - Large Commercial
  - Large (Other)
- Cross-Subsidization of Consumer Classes

RATE TYPES

- Things to Consider
  - Energy
  - Energy And Demand
  - Facilities
    - Abandonment Clauses
  - Contracts
  - Contract Terms

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

RESIDENTIAL SERVICE

SCHEDULE H-10

AVAILABILITY

Available in all territory served by the Cooperative, in accordance with the Cooperative's Service Rules and Regulations

APPLICABILITY

Applicable only for residential use, single phase churches, and for use incidental thereto supplied through one meter to each individual dwelling unit. The capacity of individual motors served under this Schedule shall not exceed 7 5 horsepower

TYPE OF SERVICE

Single-phase, 60 hertz, at available secondary voltage. (Three-phase service available under special terms and conditions for residential use only.)

RATE-MONTHLY

Base Charge - Single Phase	@	$ 8 25	per month
Base Charge - Three Phase	@	$15.45	per month
First 500 kWh per month	@	$ 0767	per kWh
Next 500 kWh per month	@	$ 0736	per kWh
Over 1,000 kWh per month			
(For Usage Months October-May)	@	$ 0540	per kWh
(For Usage Months June-September)	@	$ 0860	per kWh

MINIMUM CHARGE

The minimum monthly charge shall be the base charge plus $1 00 per kVA of installed transformer capacity in excess of 15 kVA.

BUDGET BILLING

Upon mutual agreement, the consumer may be served in accordance with the following procedure.

"The consumer's total annual consumption will be estimated and billing hereunder shall then be divided into twelve equal parts, one of which shall be rendered each month Billing for the second and subsequent twelve-month periods shall be based, in each case, upon the experience of the preceding twelve months in an effort to arrive at an approximate zero account balance at the end of each contract period."

WHOLESALE POWER COST ADJUSTMENT

The above rates shall be increased or decreased subject to the provisions of the Corporation's Wholesale Power Cost Adjustment Schedule "R".

TERMS OF PAYMENT

The bill is due upon receipt and payable within ten (10) days thereafter.

EFFECTIVE January 16, 1992
REVISED· January 21, 1993

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

SMALL COMMERCIAL SERVICE

SCHEDULE SC-11R

AVAILABILITY

Available in all territory served by the Cooperative, in accordance with the Cooperative's Service Rules and Regulations

APPLICABILITY

Applicable to all commercial service and public buildings requiring single-phase service Applicable to electric service of 200 amps or less where the Consumer's service characteristics do not necessitate multi-phase service and where multi-phase service is provided but not at the request of the Consumer Applicable to multi-phase churches and for use incidental thereto

TYPE OF SERVICE

Single-phase or multi-phase, 60 cycles, at available secondary voltages

RATE-MONTHLY

Base Charge - Single Phase	@	$ 8 25	per month
Base Charge - Three Phase	@	$15 45	per month
First 1,000 kWh per month	@	$ 1030	per kWh
Next 1,000 kWh per month	@	$ 0900	per kWh
Over 2,000 kWh per month			
(For Usage Months October-May)	@	$ 0540	per kWh
(For Usage Months June-September)	@	$ 0860	per kWh

MINIMUM CHARGES

A Single Phase Service

1 The minimum monthly charge shall be the base charge plus $1 00 per kVA of installed transformer capacity in excess of 15 kVA

B Three Phase Service

The minimum monthly charge shall be the greater of

1 The minimum monthly charge shall be the base charge plus $1 00 per kVA of installed transformer capacity in excess of 15 kVA

2 The minimum monthly charge as stated in the Contract for Electric Service, whichever is greater

WHOLESALE POWER COST ADJUSTMENT

The above rates shall be increased or decreased subject to the provisions of the Corporation's Wholesale Power Cost Adjustment Schedule "R"

TERMS OF PAYMENT

The bill is due upon receipt and payable within ten (10) days thereafter

EFFECTIVE	January 16, 1992		
REVISED	January 21, 1993		
REVISED	December 15, 1994	EFFECTIVE	December 15, 1994
REVISED	December 7, 1995	EFFECTIVE	January 1, 1996

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

LARGE GENERAL SERVICE

SCHEDULE G-11

AVAILABILITY

Throughout the Seller's service area from existing lines of adequate capacity

APPLICABILITY

To all electric service where the Consumer's service characteristics necessitate multi-phase service or where multi-phase service is provided at the request of the Consumer

TYPE OF SERVICE

Multi-phase, 60 hertz, at a standard distribution voltage

MONTHLY-RATE

Base Charge	@	$15 45 per month
Energy Charge Including Demand Charge		
First 1,500 kWh	@	$ 1319 per kWh
Next 8,500 kWh	@	$ 1164 per kWh
Next 90,000 kWh	@	$ 0925 per kWh
Over 100,000 kWh	@	$ 0850 per kWh
All consumption in excess of 200 kWh per kW of billing demand but not greater than 400 kWh per kW of billing demand	@	$ 0350 per kWh
All consumption in excess of 400 kWh per kW of billing demand	@	$ 0240 per kWh

MINIMUM CHARGES

The minimum monthly charge shall be the greater of

A $15 45 per meter plus $6 00 per kW of Billing Demand in excess of 5 kW

B $1 00 per kVA of installed transformer capacity

C The minimum monthly charge as stated in the Contract for Electric Service, whichever is greater

DETERMINATION OF BILLING DEMAND

The Billing Demand shall be based on the highest 30-minute kW measurement during the current month and the preceding eleven (11) months For the usage months of June through September, the Billing Demand shall be the greater of

(1) 100% of the measured demand for the current month.

(2) 85% of the highest demand occurring in the previous summer usage months (June through September)

For the usage months of October through May, the Billing Demand shall be the greater of

(1) 75% of the measured demand for the current month.

(2) 85% of the highest demand for the previous summer usage months (June through September)

Where there is an indication of a power factor of less than 90% lagging, the Cooperative may at its option, install metering equipment to measure Reactive Demand The Reactive Demand shall be the highest 30-minute kVAR measured during the month. The Cooperative will bill excess kVAR at the rate of $0 30 per excess kVAR.

WHOLESALE POWER COST ADJUSTMENT

The above rates shall be increased or decreased subject to the provisions of the Corporation's Wholesale Power Cost Adjustment Schedule "R"

TERM OF PAYMENT

Not less than one year for loads requiring greater than 100 kVA and up to 500 kVA of installed transformer capacity For loads requiring greater than 500 kVA of installed transformer capacity, a contract of not less than 5 years shall be required

EFFECTIVE	January 16, 1992		
REVISED	October 15, 1992		
REVISED	October 20, 1994	EFFECTIVE	October 20, 1994
REVISED	December 7, 1995	EFFECTIVE	January 1, 1996
REVISED	February 20, 1997	EFFECTIVE	March 4, 1997

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

OUTDOOR LIGHTING SERVICE

SCHEDULE OL-10

AVAILABILITY

Throughout the Cooperative's Service area from existing lines of adequate capacity

APPLICABILITY

Applicable only to outdoor lighting by ballast operated vapor lamp fixtures either mercury (MV) or high pressure sodium (HPS) and poles conforming to Cooperative's specifications Service will be rendered only at locations that, solely in the opinion of the Cooperative are readily accessible for installation and maintenance

MONTHLY RATE

Part I - Cooperative Owned and Maintained System

Section A - Rates

Lamp Wattage	Lamp Size in Lumens	Type	Rate
		HIGH PRESSURE SODIUM (Utility Type Fixtures)	
100	8,550	Open Bottom	$ 7 00
150	11,000	Cobrahead	$ 8 50
250	24,000	Cobrahead	$ 11 20
400	45,000	Cobrahead	$ 13 20
		(Flood Lighting Fixture)	
400	45,000	Directional Flood Lighting	$ 13 20
		(Underground Packages)	
100	8,550	Ornamental	$ 7 00
150	11,000	Ornamental	$ 8 50
150	11,000	Cobrahead	$15 25 n
400	45,000	Cobrahead	$18 75 n

Lamp Wattage	Lamp Size in Lumens	Type	Rate
		MERCURY VAPOR (Utility Type Fixtures)	
175	7,000	Open Bottom	$ 7 00
400	20,000	Cobrahead	$ 16 00
		(Underground Packages)	
175	7,000	Ornamental	$ 7 00
175	7,000	Ornamental	$13 90 /2
175	7,000	Cobrahead	$12 85 /2
400	20,000	Cobrahead	$18 75 /2
		METAL HALIDE (Underground Packages)	
100	6,800	Cobrahead/Ornamental	$ 7 00
175	10,800	Cobrahead/Ornamental	$ 9 00
250	17,000	Cobrahead/Ornamental	$ 11 75
400	28,800	Cobrahead/Ornamental	$ 13 50
1000	88,000	Cobrahead/Ornamental	$ 31 00

POLE CHARGES

Type	Overhead Distribution Monthly Chg	Overhead Distribution Contribution
Wood - 100 Watt HPS	$2 00 /1	$ 300
Wood - 175 Watt MV	$2 00 /1	$ 300
Wood - 150 Watt HPS	$2 50 /1	$ 300
Wood - All Other	$2 80 /1	$ 300
Ornamental (Fiberglass)	$6 90 /2	$ 400
Metal	NA	$1,000

/1 These monthly rates apply for service where wood poles were installed in lieu of a contribution. These rates are applicable to locations where prior service has been provided but not available for new facilities installed after May 15, 1989

/2 These monthly rates apply for service where metal poles, underground service and ornamental fixtures were installed in lieu of a contribution These rates are applicable to locations where prior service has been provided but not available for new facilities installed after March 16, 1986

Section B - Contributions

1 Wood Poles - The member will be required to pay a one time non-refundable contribution-in-aid of construction of $300 00 per pole for the installation of each wood pole requested for the purpose of receiving outdoor lighting service When the member makes such contribution, the monthly rate shall be the appropriate rate for existing overhead distribution on a wood pole

2 Metal Poles - At the member's request and after payment by the member to the Cooperative of a one time non-refundable contribution-in-aid of construction of $1,000 00 per metal pole, the Cooperative will install metal poles The monthly rate shall then be the appropriate rate for existing overhead distribution on a metal pole

3 Ornamental Fixtures and Poles - Ornamental fixtures and poles will be provided by the Cooperative under the following terms

a) Ornamental fixtures and poles provided hereunder are those considered "standard" by the Cooperative and consist of, a) square traditional fixture, or b) round traditional fixture Non-standard fixture and poles may be consumer owned and maintained and if considered consumer owned will be billed under Part II, Section A, "Consumer Owned System" of this schedule

b) A one time non-refundable contribution-in-aid of construction of $400 00 per ornamental fixture and pole will be required to cover the cost of ornamental fixtures and poles When the member makes such contribution, the monthly rate shall be the appropriate rate for existing overhead distribution on a wood pole

4 Other Poles - The member may request, and at the sole discretion of the Cooperative to agree, that the Cooperative install and maintain a pole or fixture not covered above If the Cooperative agrees, the member will be required to make a one-time, non-refundable contribution-in-aid of construction in the amount of $1,000 per pole The remaining investment in facilities may qualify for the Corporation's Facilities Charge Rider as outlined in Schedule FC and all aspects of this schedule will apply to this investment. The monthly rate shall then be the appropriate rate for existing overhead distribution on a metal pole

5 Underground Service - Fixtures served by underground wiring will be available (except in certain residential areas served by overhead distribution and certain underground areas served by network type systems) upon payment by the member of a one time non-refundable contribution-in-aid of construction amounting to $0 80 per foot of buried cable, per fixture

Part II - Consumer Owned System

Section A - Monthly Rates

$1 00 per month per light, plus 4 2¢ per kWh

Section B - General Notes

1 kWh shall be the sum of the nominal wattage and ballast wattage of each light times 4,000 hours, divided by 12 divided by 1,000

2 The Cooperative may, at its option, verify kWh by installing a kWh meter or device to limit connected load

3 The number and location of service points shall be as specified by the Cooperative

4 In no case shall the Cooperative expend more than three times the estimated annual revenue to be derived from the service

5 The term "consumer owned system" means complete ownership by the consumer of all facilities (including poles, fixtures, circuits, and disconnection devices) up to the point of connection to the Cooperative's existing supply lines

The consumer shall provide (a) suitable mounting and wiring for a photo-electric receptacle supplied by the Cooperative, and (b) a weatherproof enclosure, if needed, for any relay supplied by the Cooperative The Cooperative will supply the necessary photo-electric control

6 The minimum monthly charge shall be $8 25 per month per service points

7 Service hereunder will require a written contract between the cooperative and the consumer prior to service being made available The original term of this contract shall be a minimum of one year and thereafter until terminated by either party on thirty (30) days written notice, but the Cooperative may require a contract of original term up to five (5) years, and may require an advance payment up to one-half of the estimated revenue for the term of the contract

TERMS OF PAYMENT

The bill is due upon receipt and payable within ten (10) days thereafter

EFFECTIVE	January 16, 1993		
REVISED	July 15, 1993		
	December 16, 1993		
	March 17, 1994	EFFECTIVE	April 4, 1994
	June 15, 1995	EFFECTIVE	July 17, 1995
	June 20, 1996	EFFECTIVE	June 20, 1996
	August 15, 1996	EFFECTIVE	August 15, 1996
	December 27, 1996	EFFECTIVE	January 1, 1997
	May 15, 1997	EFFECTIVE	August 15, 1997

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

RESIDENTIAL TIME-OF-USE RATE

SCHEDULE TU-12

AVAILABILITY

Available in all territory served by the Cooperative in ccordance with the Service Rules and Regulations

APPLICABILITY

Applicable to residences otherwise served under Schedule H-10

CONDITIONS OF SERVICE

1. The consumer must require permanent year around service

2. The consumer must agree to take service under Schedule TU-12 for a minimum of 12 consecutive months

3. Schedule TU-12 will be limited to the first 500 applications from qualifying consumers receiving service on or after the effective date

4. Schedule TU-12 will be further limited to new or existing consumers who meet the "Good Cents" home requirements

TYPE OF SERVICE

Single-phase, 60 hertz, at available secondary voltages (Three-phase service available under special terms and conditions for residential use only)

RATE - MONTHLY

Base Charge -	Single Phase	@	$10 50 per month
	Three Phase	@	$17 70 per month
All kWh of Off-Peak Energy		@	4 1 cents per kWh
All kWh of On-Peak Energy		@	29 0 cents per kWh

MINIMUM CHARGES

The minimum monthly charge shall be the base charge plus $1.00 per kVA of installed transformer capacity in excess of 15 kVA

WHOLESALE POWER COST ADJUSTMENT

The above rates shall be increased or decreased subject to the provisions of the Corporation's Wholesale Power Cost Adjustment Schedule R

DETERMINATION OF ON-PEAK AND OFF-PEAK ENERGY

The On-Peak Period shall be those hours, Monday - Friday, beginning at 3 00 p m and ending at 8 00 p.m during the summer months (June 1 - September 10), excluding July 4 and Labor Day All other hours shall be considered the Off-Peak Period

The On-Peak Energy shall be the kilowatt-hours recorded during the On-Peak Period The Off-Peak Energy shall be the kilowatt-hours recorded during the Off-Peak Period

TERMS OF PAYMENT

The bill is due upon receipt and payable within ten (10) days thereafter

ADOPTED. February 18, 1993

REVISED· June 17, 1993

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

LARGE POWER TIME-OF-USE RATE

SCHEDULE TOU-14

AVAILABILITY

Available to Members of the Cooperative that meet the following requirements:

1 The load at each delivery point must be a single consumer at a single location.

2. The meters shall be read on the same dates used for the Cooperative's wholesale billing from the Oglethorpe Power Corporation (OPC).

3. The load must have a connected demand of 900 kW or greater and maintain a billing load factor of 65% or greater. Load factor shall be computed annually using the twelve (12) months ending September 30 of the previous year. This requirement will be satisfied if both conditions are met in either of the past two years. Loads not previously served by the Cooperative may satisfy this requirement with estimated data for two years Billing load factor shall be computed for each year ending September 30 as the annual amount of energy consumed during the year divided by the product of the load's average demand coincident with OPC's 20 highest demands during OPC peak period notification hours and the number of hours in the corresponding year

SCHEDULE OF CHARGES (Monthly)

A. Wholesale Power Cost

Service Charge

$1,250.00 per month

Demand Charges

$7.11 per kW of On-Peak Demand
$1.20 per kW of Excess Off-Peak Demand

Energy Charges

4 95¢ per kWh of On-Peak kWh

2 50¢ per kWh of Off-Peak kWh

Other Wholesale Charges

In addition to the above charges, any other charges, surcharges, riders, etc , contained in Rate Schedule D to the Wholesale Power Contract between OPC and the Cooperative.

Wholesale Facilities Charge

The full or prorated amount of any facilities charge billed to the Cooperative by Oglethorpe Power Corporation pertaining to the investment in facilities provided by Oglethorpe Power Corporation specifically in order to furnish service hereunder.

Energy Cost Adjustment Provision

All billing rendered under this rider shall be respectively increased or decreased in an amount per kWh equal to the amount of the Energy Cost Adjustment Provision billed by OPC for service hereunder.

B Sawnee Electric Membership Corporation Facilities Charge

The dollar investment in facilities provided by the Cooperative specifically in order to furnish demand and energy to the consumer times a monthly carrying cost factor.

C. Sawnee Electric Membership Corporation Service Charge

1) $ 100 plus

2) 5 0 % times the amount determined in Section A above.

DETERMINATION OF ON-PEAK/OFF-PEAK TIME PERIODS

On-Peak Time Period

The on-peak time period is defined as all hours from 4:00 p.m to 10 00 p.m. daily, occurring during the months of June through September

Off-Peak Time Period

The off-peak time period is defined as all hours not defined as On-Peak above

DETERMINATION OF DEMAND

On-Peak Demand:

For the Billing Month of January, the On-Peak Demand shall be the load's maximum demand occurring during the On-Peak Period of the 12 months ending September 30 of the previous year.

The On-Peak Demand will be effective for monthly billings from January through December.

Excess Off-Peak Demand·

For each Billing Month, the Excess Off-Peak Demand shall be calculated by subtracting the On-Peak Demand requirement from the load's maximum demand recorded at any time during the month

DETERMINATION OF ON-PEAK AND OFF-PEAK ENERGY

On-Peak Energy shall be all kWh used during the on-peak time period.

Off-Peak Energy shall be all kWh used during the off-peak time period.

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NEW TIME-OF-USE LOADS

For existing loads newly covered by the Large Time-Of-Use Rate and not previously metered on an hourly basis, the Demand requirements shall be based on estimates developed by OPC and the Cooperative

DETERMINATION OF EXCESS REACTIVE DEMAND

Excess Reactive Demand shall be any excess of the measured kVAR at the time of the greatest kW demand at the point of delivery during a month over one-half of such kW demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the amount specified in the contract for electric service.

BILLING ADJUSTMENTS

An independent engineering estimate of the transformation and line losses from the wholesale metering point shall be made and such losses shall be added to the member's, metered billing units before the computation of charges as stated above

WHOLESALE RATE ADJUSTMENT

Should there be any change in the wholesale rate under which the Cooperative purchases power from Oglethorpe Power Corporation, the Cooperative reserves the right to modify the charges and provisions stated above correspondingly.

TERMS OF PAYMENT

All bills are net and payable according to the provisions stated in the contract for service between the Cooperative and the member.

EFFECTIVE. January 1, 1993

REVISED. November 18, 1993
November 17, 1994 EFFECTIVE January 1, 1995

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

TIME-OF-USE - LARGE GENERAL SERVICE
SCHEDULE TOU-LGS-1

I AVAILABILITY

Throughout the Corporation's service area from existing lines of adequate capacity

II APPLICABILITY

This rate schedule is applicable to loads which qualify to receive service under the Corporation's Rate Schedule SC-11 and G10-R.

III CONDITIONS OF SERVICE

A The consumer must require permanent year around service

B The Consumer must agree to take service under Schedule TOU-LGS-1 for a minimum of 12 consecutive months

C Schedule TOU-LGS-1 will be limited to the first 100 applications from qualifying consumers

D Schedule TOU-LGS-1 will be considered experimental for a period of two (2) years from its adopted date Consumers who wish to receive service under this rate must understand that anytime during and at the end of the experimental period the rate could be changed or entirely eliminated.

IV TYPE OF SERVICE

Single or three phase, 60 hertz, and at a standard voltage

V MONTHLY RATE

A	Customer Charge - 1 Phase	$50 00
	Customer Charge - 3 Phase	$225 00

B Energy Charges

On-Peak kWh	$0 150 per kWh
Off-Peak kWh	$0 036 per kWh

C Demand Charges

On-Peak Demand	$15 00 per kW
Excess Demand	$ 5 00 per kW

VI ON PEAK PERIOD

The on-peak period for the calendar months of June through September (Summer Months) is defined as the hours starting at 1 00 p m and ending at 8 00 p m , Monday through Friday, excluding the days on which the following holidays are observed Independence Day and Labor Day For the calendar months of October through May (Winter Months), there shall be no hours defined as on-peak

VII OFF-PEAK PERIOD

The off-peak period for June through September (Summer Months) is defined as all hours not included above in the on-peak periods, including all weekends and holidays For the calendar months of October through May (Winter Months), the off-peak period is defined as all hours

VIII DETERMINATION OF BILLING DEMAND

On Peak Demand On-Peak Demand shall be the highest 30-minute kW measurement during the On-Peak Period, as defined above, for the current month.

Excess Demand Excess Demand shall be equal to the highest 30-minute kW measurement during all hours of the current month minus the On-Peak kW for the current month.

IX DETERMINATION OF REACTIVE DEMAND

Where there is an indication of a power factor of less than 90% lagging, the Corporation may at its option, install metering equipment to measure Reactive Demand The Reactive Demand shall be the highest 30-minute kVAR measured during the month. The Corporation will bill monthly excess kVAR at the rate of $0 30 per excess kVAR.

X MINIMUM CHARGES

The minimum monthly charge shall be the greater of

A $225 00 per meter plus $6 00 per kW of Billing Demand in excess of 40 kW, or

B $1 00 per kVA of installed transformer capacity, or

C The minimum monthly charge as stated in the Contract for Electric Service, whichever is greater

XI WHOLESALE POWER COST ADJUSTMENT

The above rates shall be increased or decreased subject to the provisions of the Corporation's Wholesale Power Cost Adjustment Schedule "R"

XII TERM OF CONTRACT

Not less than one year for loads requiring greater than 100 kVA and up to 500 kVA of installed transformer capacity For loads requiring greater than 500 kVA of installed transformer capacity, a contract of not less than five (5) years shall be required.

XIII TERMS OF PAYMENT

The bill is due upon receipt and payable within ten (10) days thereafter or as may be stated on the bill

XIV ADDITIONAL ADJUSTMENTS AND RIDERS

The bill calculated at the above rate is subject to change in such an amount as may be determined under the provisions of the Corporation's Service Rules and Regulations which are on file with the Georgia Public Service Commission or upon action by Sawnee EMC's Board of Directors including but not limited to termination of this schedule

ADOPTED	June 15, 1995	EFFECTIVE	June 15, 1995
REVISED	August 17, 1995	EFFECTIVE	August 17, 1995
REVISED	March 21, 1996	EFFECTIVE	March 21, 1996

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

LARGE POWER SERVICE

SCHEDULE LPS-1

I AVAILABILITY

Available to any Member of the Corporation that meets the following requirements

A The load at the delivery point must be a single consumer at a single location, and an agreement for electric service entered into after June 1, 1996

B The meters may be read on the same dates used for the Cooperative's wholesale billing from its power supplier

C A minimum connected load must equal 900 kW or greater

D Existing consumers who received initial service prior to June 1, 1996 may receive service under this rate with an access charge

E Consumer agrees to be subject to the Cooperative's Service Rules and Regulations

II TYPE OF SERVICE

Service shall be provided as set forth in the contract for service between the Corporation and the consumer

III RATE PER MONTH

The monthly bill will consist of the sum of the following charges

A Power Supply Costs[1]

Demand Charges

Charges in dollars per kW of Power Supply Demand will be determined on a case per case basis

Energy Charges

The rate per kWh of all energy for service under this schedule will be determined on a case per case basis

B Integrated Transmission System (ITS) Costs

1) The cost per kW of Power Delivery Demand will be determined on a case per case basis, plus

2) ITS Substation Related Costs Determined by one of two methods as follows

Method 1 - $0 37 per kW of monthly maximum billing demand for consumers served from substations serving the Corporation's primary distribution system, or,

Method 2 - A direct assignment of ITS Substation costs Method 2 only applies for consumers served from a dedicated ITS substation

C Distribution System Costs

1) $2 57 per kW of Monthly Maximum Billing Demand for consumers connected to the Corporation's joint use primary distribution facilities, plus

2) Corporation Facilities Charge - The dollar investment in dedicated service facilities provided by the Corporation specifically in order to furnish demand and energy to the consumer times a monthly fixed charge rate

D Corporation Service Charge

A service charge consisting of $100 00 per month plus one percent (1%) of the sum of A and B above

IV DETERMINATION OF POWER SUPPLY BILLING DEMAND

For the billing months of January through the following December, the power supply billing demand shall be the highest demand measured in any 60-minute period during June through September of the previous year

V DETERMINATION OF POWER DELIVERY DEMAND

For the billing months of January through the following December, the power delivery demand shall be the consumer's average demand coincident with the five highest ITS demands occurring during the 12 months ending September 30 of the previous year

VI DETERMINATION OF MONTHLY MAXIMUM BILLING DEMAND

The monthly maximum billing demand shall be the greater of

1) the highest 60-minute measurement during the current month, or

2) fifty percent (50%) of the highest 60-minute measurement occurring during the preceding eleven (11) months

VII DETERMINATION OF REACTIVE DEMAND CHARGE

Where there is an indication of a power factor of less than 90% lagging, the Corporation may at its option, install metering equipment to measure Reactive Demand. The Reactive Demand shall be the highest 60-minute kVAR measured during the month. The Excess Reactive Demand shall be kVAR which is in excess of one-half the measured kW in the current month. The Corporation will bill excess kVAR at the rate of $0 30 per excess kVAR.

VIII MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the sum of the charges contained in Section A, B, C, and D in the above provisions entitled "RATE PER MONTH" plus applicable taxes and access charges

IX TAXES

The consumer shall pay, in addition to all other charges from above, any sales, use, franchise, gross receipt or any other tax now or hereafter applicable to service rendered, which tax shall be added to each bill, unless the consumer furnishes satisfactory evidence that it is exempt herefrom

X BILLING ADJUSTMENTS

An independent engineering estimate of the transformation and line losses from the wholesale metering point shall be made and such losses shall be added to the member's metered billing units before the computation of charges as stated above

XI TERMS OF PAYMENT AND LATE PAYMENT CHARGES

All bills are net and payable according to the provisions stated in the contract for service between the Corporation and the member

XII COGENERATION SERVICE RIDER

The above rates shall be adjusted, to those consumers of the Corporation who qualify under Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) as a cogenerator or small power producer, by the amount determined under Rate Rider QF-14

XIII ACCESS CHARGE

For existing consumers, this rate schedule is available with an access charge The access charge is based on the most recent 12-month billing history and represents the difference in historical annual billings under the standard rates applicable to the existing consumer compared to the annual billings calculated for the same historical period under Schedule LPS-1 This charge will decline 20% per year, after the first year, to equal zero (0) at the end of the fifth year This charge will not be less than zero (0) or a negative

XIV WHOLESALE RATE ADJUSTMENT

Should there be changes in the Corporation's costs for purchased power or power production, the Corporation reserves the right to modify the charges and provisions stated above corresponding

[1] The applicable Power Supply Cost will be determined on a case by case basis Availability of power, transmission constraints, available capacity, and other factors will determine the proposed pricing

APPROVED June 20, 1996 EFFECTIVE June 20, 1996

PLANNING AND BUDGETING

- Power Requirements
  - Sales
  - Purchases
  - Losses
  - Own Use
- Financial Forecast
  - Long Term
  - Short Term

SUPPORTING

REFERENCE

MATERIAL

Electric Utility Knowledge Handbook

POWER•UP

Finance and Rate Design

HOUSTON LIGHTING & POWER COMPANY

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Finance and Rate Design

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FINANCE

FINANCIAL CONCEPTS

FERC Uniform System of Accounts

All businesses have found it necessary to create classifications or charts of accounts that apply to their particular needs Any system of accounts is designed to help guide and define business operations Utility accounting is essentially the same as accounting in any other business Initial source financial transactions are grouped, summarized, and recorded in accounts The account balances are then used as a basis for preparation of financial statements An underlying aspect of the accounting process is the element of internal control It is the responsibility of management to maintain a system of internal control that provides reasonable assurance that all transactions and entries into the books and records are authorized, approved, and properly reflected in the financial statements Management, investors, creditors regulatory agencies, and others depend on accounting information to assist them in decision making

The Federal Power Act of 1935 specifically authorized the establishment of a uniform system of accounts for electric and gas utilities, and prescribed how these accounts were to be used This Federal Energy Regulatory Commission (FERC) uniform system of accounts and corresponding rules was subsequently adopted by most state regulatory agencies including the Public Utility Commission of Texas The FERC system of accounts prescribes accounting classifications and instructions whereby utilities can achieve a reasonable standardized method of keeping their records for financial reporting, ratemaking, and other regulatory needs These accounting classifications maintain consistent application among companies for expenditures charged to capital or expense

Regulatory accounting requirements and regulatory reporting requirements go hand-in-hand Regulatory reporting represents one of the primary means by which

commissions oversee compliance with their accounting requirements and also fulfill their other regulatory responsibilities In the exercise of their responsibilities, regulatory commissions must investigate and review the operations of utilities within their jurisdiction This requires a lot of accounting oriented information In order to ensure that the actions of regulators are reasonable and consistent and that utilities are regulated on a comparable basis, uniformity of accounting treatment, as well as consistency of treatment from period to period, is necessary

Structure of the Uniform System of Accounts

Several components are basic to the uniform system of accounts

(1) A detailed list of specific account numbers and account titles for recording all accounting transactions

(2) A definition of each account, describing the types of transactions to be recorded in the account

(3) Instructions regarding the accounting basis for recording amounts in the specific accounts

(4) General instructions and definitions for using the systems of accounts including the maintenance of accounting records required for audit trails, and retention and destruction requirements

An example of the general numbering system that is followed by electric utilities is shown below

First Digit of Account Number	Type of Account	Example
1	Asset	131 - cash
2	Liability or capital	232 - accounts payable
3	Electric plant	312 - boiler equipment
5	Operation and maintenance expense	512 - boiler maintenance
9	Customer, customer service, administrative, and general expenses	921 - office supplies

In apr ng the uniform system of accounts, a lity is not precluded fr developing sub-accounts, departmental accounts, and other accounting records that supplement those required by the FERC uniform system These additional accounts may be needed for management information purposes as well as cost efficient accounting and reporting reasons in that a large and comple company such as HL&P generates hundreds of thousands of transactions in the normal course of business For example, accoun 921 takes on many sub-accounts to distin different types of expenditures

9 00 Expenses of general office employees

921-300 General office supplies and expenses

921- 0 Membership dues - employees

The Income Statement

The income statement is a summary of the Company's revenue and expenses for a specified period of time Income statements are typically prepared monthly A non-regulated company would probably produce an income statement as shown in Figure 1, whereas a regulated utility would structure an income statement as shown in Figure 2 Simply stated, income is the amount that remains after expenses have been deducted from revenues

Revenues are almost exclusively the amount charged to customers for services From this income or return, the company must pay the interest charges on its outstanding debt and dividends to preferred stockholders The remainder is left for payment of dividends to common stockholders and reinvestment in the business

Operation and maintenance expense accounts are used for recording the normal operating costs of the company, and include wages (excluding the cost of construction labor), maintenance of property and equipment, fuel used to generate electricity, and other expenses

Depreciation and amortization accounts represent the allocation of costs of utility plants over their expected useful lives of supplying electric service Including this depreciation as an expense has the effect of designating a portion of the revenue collected from customers for recovery of the investment in the utility plant

Accounts for taxes are used to record taxes on real and personal property, gross receipts, social security taxes, etc

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Statement of Income
Year ended December 31, _____
(in thousands)

Sales and operating revenues		$ 9,367,965 00
Cost of sales	$ 7,090,050.00	
Distribution, administrative, and general expenses	1,500,360.00	
Depreciation	219,410.00	
Operating costs and expenses		8,809,820 00
Operating profit		558,145 00
Other income		153,210 00
Interest expense		(142,340.00)
Income before income taxes		569,015.00
Income taxes		120,010 00
Net income		$ 449,005.00
Dividend on Preferred Stock		11,000 00
Earnings on Common Stock		438,005 00
Earnings Per Share of Common Stock		$ 5.10

Figure 1: *Example of the statement of income of a non-utility company*

Where We Get Our Income

HL&P is subject to a statutory process used to regulate the prices that we may charge our customers for utility services We get an exclusive right to serve an area and give up the right to set the prices for this service This, in effect is a surrogate for free market competition Under this regulation, the total annual revenue requirements are limited to an amount that will yield a specified annual return on the value of property used and useful in public service (the rate base), plus the necessary and proper operating expenses, taxes, and depreciation Ratemaking is the process of determining the revenue requirements of the utility's service that meets the test of reasonableness to customers while permitting shareholders (investors) a fair return on their investment This process can be simplified for explanation purposes, but in reality it

Statement of Income
Year ended December 31, _____
(in thousands)

Operating Revenues	
Electric	$ 4,156,654 00
Gas	2,538,291 00
Total Operating Revenues	6,694,945 00
Operating Expenses	
Operation	
Cost of Electric Energy	2,623,160 00
Cost of Gas Sold	1,870,244 00
Transmission	116,102.00
Distribution	136,008 00
Other	568,030.00
Total Operation	5,313,544.00
Maintenance	182,111 00
Depreciation and Amortization	322,152.00
Taxes Other Than Income Taxes	105,001 00
Federal and State Income Taxes	125,006.00
Total Operating Expense	6,047,814 00
Operating Income	647,131.00
Other Income and Income Deductions	
Allowance for Other Funds Used During Construction	226,002.00
Interest Income	81,050 00
Other - Net	68,029 00
Federal and State Income Taxes	
Applicable to Other Income	(22,046 00)
Total Other Income & Income Deductions	853,035.00
Income Before Interest Charges	1,000,166.00
Interest Charges	
Interest on Long-term Debt	877,004 00
Other Interest Charges	118,452.00
Allowance for Borrowed Funds Used During Construction	(59,363.00)
Total Interest Charges	436,093 00
Net Income	$564,073 00
Dividends on Preferred Stock	$134,050 00
Earnings Available For Common	$480,023 00
Dividends Declared Per Common Share	$1.95 00
Earnings Per Share of Common Stock	$2.21 00

Figure 2: *Example of the statement of income of a utility company*

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is very complicated involving application of principles of economics, accounting, statistics, law, engineering, and public relations

The accounting equation to derive our income is really pretty simple It is how we get there that is very complicated

Rate Base X Rate of Return = Return on Investment **(Operating Income)**

Return on Investment + Operating Expenses = Revenue Requirements

FINANCIAL ANALYSIS

COMPETITION

Electric utilities are moving into a new era To prepare for this new era and to meet the challenges of an increasingly competitive environment HL&P must look at the way we conduct our business from a different perspective We must not only do things more efficiently with fewer resources, we must do this while providing lower cost service and more options to our customers

FINANCIAL ANALYSIS

As HL&P moves into position to compete in this new competitive environment, it is imperative that economic evaluations be a part of the continuous day-to-day operations of each business unit

The four main steps that are important in financial analysis are

Step 1 Define the problem or opportunity
Step 2 Identify all reasonable options
Step 3 Identify and estimate expected cash flow
Step 4 Evaluate projects using sound investment rules

The following information provides insight and guidance into performing each of these steps This is a very condensed version of the Financial Analysis Course on the Discounted Cash Flow (DCF) methodology For more in-depth information about this course, contact Financial Services

➤ *Step 1· Define the problem or opportunity*

In the work environment, it is important to continually look for ways to improve the quality of work and become more aware of financial analysis methods

The first step in performing a financial analysis is to identify problem areas and seek new opportunities Initially, a problem or opportunity must be correctly defined For example fixing an inoperative car is not the problem It is only one solution to the problem of transportation needs

➤ *Step 2 Identify all reasonable options*

Once the problem is defined, all possible options of rectifying the problem must be considered It is important to challenge traditional assumptions and to be innovative in identifying the options available

Not all options will warrant an economic evaluation For example, another option to solving the problem of transportation needs besides fixing an inoperative car, is to walk However, this solution would not be reasonable if transportation was needed mainly to go to and from work — and the work place was located 20 miles from home Only those options considered reasonable should be included in the financial analysis

➤ *Step 3 Identify and estimate expected cash flows*

A finance axiom says that "Only cash flow matters " "Income" and "cost" in the accounting sense are not the same as cash flow

Identify expected cash flows.

It is important to identify all cash flows that will result from an investment decision For example when purchasing a car the related cash flows would include not just the original investment or purchase price but also the ongoing cost for insurance fuel and maintenance If the car allowed you to avoid other transportation costs, the cash "inflows," or savings should also be included These include current and future year impacts

Cash flow is a comparison of (1) all costs associated with pursuing a new project, to (2) all costs associated with not pursuing the project ("status quo") This can simplify estimation and explanation of savings associated with the investment

Items such as book depreciation, overhead costs, and sunk costs are excluded from the cash flow analysis.

Book depreciation is the depreciation expense used for financial reporting purposes Unlike tax depreciation, which affects cash flows through tax payments, book depreciation does not represent cash flow and should not be included in a discounted cash flow analysis

Overhead costs reflect allocations of costs that are generally assumed to be fixed Some examples of overhead costs are "stores" costs and engineering costs Overhead costs would be included only if they were to change as a result of implementing one of the project alternatives For example, if total engineering costs were reduced for a given project, engineering overhead costs would also be reduced

Sunk costs are costs incurred in the past that have no impact on the current alternatives under evaluation For example the fact that you painted your car last year (sunk cost) would not be a part of determining whether to keep driving the car or buy a new car

It is important to identify the impact of inflation on cash flows The impact of inflation can be significant on multiple year projects

Estimate expected cash flows.

Inflation assumptions are calculated by the Corporate Planning Department and can be provided for specific categories of costs (e g , steel, labor, gas prices)

When making assumptions about cash flow impact, it is important to assess the level of certainty about each cash flow estimate For some projects, cash flows can be estimated with a high level of certainty For other projects, there may be some estimates that are uncertain It is important to incorporate sensitivity analysis in these cases

The discounted cash flow method of financial analysis considers capital and operating expenses on an after-tax basis. The true cost to the Company of the expense is *net* of the tax savings from the federal income tax deduction

In defining cash flows, capital expenditures are distinguished from O&M expenses because they are treated differently for tax purposes O&M expenses are deductible for tax purposes in the period they are incurred Capital expenditures qualify for tax depreciation over several years However, while the capital expenditure for an asset is not deductible for tax purposes the related tax depreciation expense is deductible Tax depreciation results in actual cash inflows because these non-cash expenses are deductible and reduce the amount of federal income tax paid

Contact the Corporate Tax Department to find out the depreciable life of an asset for tax purposes and the percentages to use in calculating the yearly tax depreciation expense

➤ *Step 4: Evaluate projects using sound investment rules*

In the past HL&P used the revenue requirements methodology for economic evaluations However, due to the Corporate focus on net cash flow and the need to evaluate projects in a competitive environment, the Company has changed to the DCF methodology

The DCF technique was developed to adjust for the time value of money by applying a discount rate to a stream of cash flows so that future inflows and outflows can be expressed in current day dollars

The time value of money is the price put on the time an investor waits for a return on an investment (For example, annual interest rates given by a bank on savings accounts are what that bank is willing to pay you to use your money for a year)

A dollar received today is worth more than a dollar received in the future because the dollar today can be invested to earn interest For example, $100 invested in the current time period at 10% interest will be worth $110 after one period in the future

Conversely, a dollar received in the future is worth less than a dollar received today because the opportunity to earn interest on the dollar is lost For example, investors would have to receive $110 in the future if the interest rate is 10% to have the same monetary value as they would have had if they received $100 in the current period

The net present value (NPV) is the sum of the discounted future cash flows and the initial cash flow

When making economic comparisons among projects, the monetary expenditures associated with implementing the various projects usually occur at different times and in different amounts To make a decision based on the least cost alternative, we need a method to compare, on an equivalent basis the differing cost streams of various projects The net present value analysis is the method used to accomplish this

Using this method two project alternatives, with very different cost flow characteristics, can be compared using their present values The present value is calculated by multiplying the future cash flow by a present value interest factor used to discount future cash flows back to today The present value interest factor is dependent on the number of time periods and the interest or discount rate

The discount rate to be used for evaluating alternative projects may be obtained from the Treasury Department (*Note* This discount rate is also called the *weighted average marginal after-tax cost of capital*)

There are some exceptions to the use of the weighted average marginal after-tax cost of capital as the discount rate One exception would be — if the analysis is an evaluation of leasing vs purchasing an asset This would represent a financing decision, as opposed to an investment decision

When considering a lease option, the investment decision needs to be made first using the DCF method Once the decision is made to invest in an asset then the method of financing the asset can be decided by performing a lease vs purchase analysis This consists of using the DCF method to compare (1) the NPV of the cash flows of leasing, to (2) the NPV of the cash flows of purchasing The after-tax cost of debt is used in this comparison

Other investment decision methods (in addition to DCF) include discounted payback, sensitivity analysis, and deferral analysis

These methods can provide useful information regarding how projects are evaluated Of course, these are only tools and other judgment factors must also be considered in determining a projects viability

It is not necessary for each of us to be an expert in using financial concepts However it is important that we understand these concepts so that we ask appropriate questions in evaluating projects and meeting the demands of a competitive environment

RATE DESIGN

INTRODUCTION

In most of the Company's financial reports HL&P's customers are broadly categorized as residential commercial industrial, and other Each of these customer groups includes customers served under several rate schedules For example, the "commercial" category includes certain streetlighting customers, guard lighting customers, and some of the customers served under the Miscellaneous General Service (MGS) rate Therefore, any statistics concerning these "customer class" groupings should not be confused with discussions of statistics related to the various "rate classes "

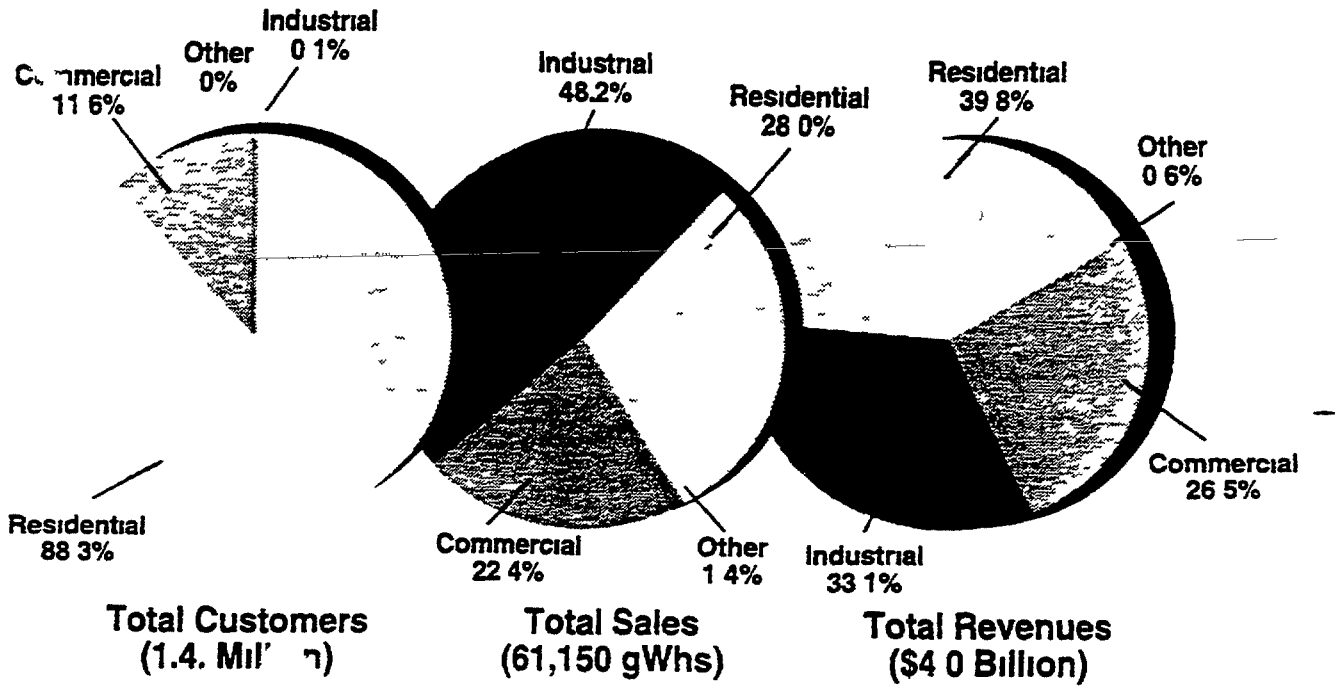

Figure 1

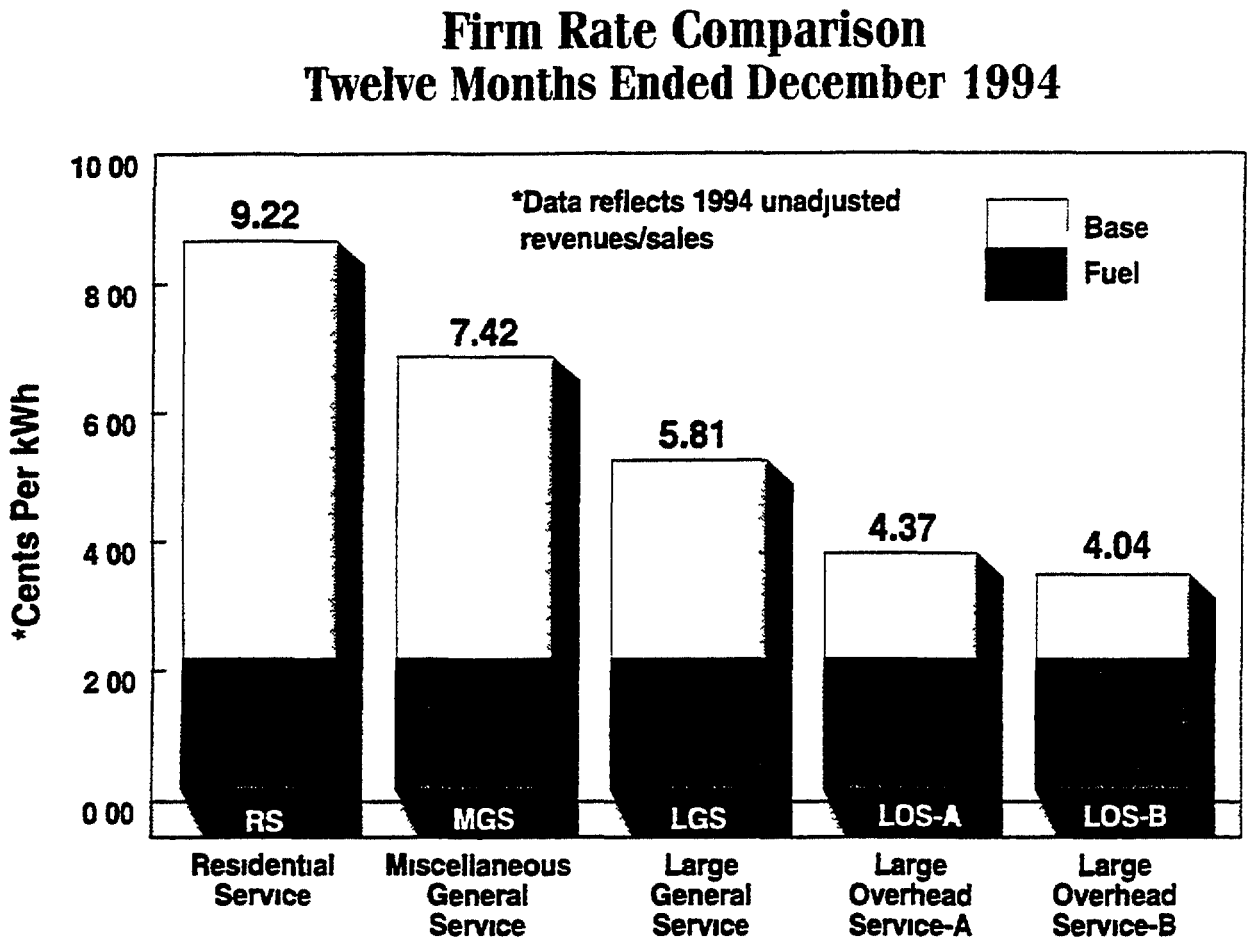

Figure 2

Industrial customers, although small in numbers are important in terms of revenue contribution They account for approximately one-third of total Company revenues, yet number less than 1,700 The very largest of these industrial customers are served directly from our transmission lines and number less than 100 Commercial customers are a much more diverse group This group includes over 170 000 customers This group is made up of such entities as bill boards bowling alleys cafes dentist offices office buildings hospitals grocery stores and numerous and various other types of customers The residential customer class is made up of the largest number of customers — this group accounted for about 40% of the total Company revenues in 1994

A comparison of HL&P's 1994 rates is shown in Figure 2 The customer's cost per kWh for electricity varies between the different rate classes The variation in cost to the customer reflects the difference in the Company's cost to serve that rate class For

example, LOS-A and LOS-B customers (which are transmission customers only) do not use and do not pay for distribution s as do residential custo~ers

When Is a Rate Case Necessary?

When e Company's revenues do not adequately cover the cost of service and/or do not adequately provide for the financial integrity of the Company, the Company can petition the PUC for a rate increase Alternatively, on the complaint by any affected party or on the PUC's own tion, the PUC may hold hearings to determine if the Company's rates are unreasonable or in any way in violation of any provisio of applicable law Cost of service (also called revenue requirement) has two components allowable expenses and return on invested capital

Allowable expenses include only those expenses which are reasonable and necessary to provide service to the public and are based on a historical test year Allowable expenses include such items as operations and maintenance expense depreciation expense, assessments and taxes (including federal income taxes), advertising contributions, and donations (within certain limits and guidelines), and others Some expenses are never allowed as a component of cost of service For example legislative advocacy expenses, funds expended in support of political candidates member p in social, recreational, fraternal, or religious clubs or organizations, and any expenditure found by the PUC to be unreasonable, unnecessary, or not in the public interest

Return on invested capital is the rate of return multiplied by invested capital Rate of return, expressed as a percentage of invested capital, is set by the commission and is de ed at the time that it is set to be reasonab sufficient to assure confidence in the financial soundness of the Company and to be adequate to maintain and support the Company's credit needs and enable the Company to raise the money necessary for the proper operation of the utility In setting the rate of return, the commission may consider inflation, deflation, the growth rate of the Company's service area, and the Company's need to attract new cap l *Invested capital* (also called rate base) includes as the major components the original costs of plant, property, and equipment less accumulated depreciation Therefore a rate of return may be reasonable at the time it is set and then become too low or too high due to changes affecting opportunities for investment, the money market and business conditions generally

It is therefore possible for the Company to be receiving enough revenue to cover its

allowable expenses and its *allowed* return on invested capital but still need rate relief due to changes in financial circumstances which make the rate of return inadequate

What are Base Rates And Total Bill?

Base rates are those charges specifically stated in the rate schedules (i e , RS, MGS, LGS, LOS-A, and LOS-B) The base rate charges include a facilities or customer charge ($ per month), a demand charge ($ per kVA, not applicable to RS and lighting service rates), and an energy charge ($ per kWh) Each of these charges has a specific dollar amount stated on the rate schedule and are fixed until a general rate case changes them

Total bill includes all of the costs included on the customer's electric bill including the base rates The items other than base rates are fuel charges and other adjustments Fuel charges recover the cost of reconcilable fuel expense and the specific rate ($ per kWh) is shown on Rider FC in the Company's tariff book rather than on each individual rate schedule The fuel charge may change (either increase or decrease) in a fuel proceeding outside of a general rate case

Other adjustments include items which, like the fuel charge, can change periodically outside a general rate case These other adjustments include Power Cost Recovery Factor (PCRF), House Bill 11 Tax Adjustment (identified as "Cost of Service Surcharge or Credit" on customer bills), municipal franchise fee (applies only to certain rates), and city, state and county sales taxes PCRF allows the Company to charge or credit its customers for the costs of capacity purchased from cogenerators and small power producers to the extent that such costs vary from the costs included in the base rates which were set in the Company's most recent general rate case The "Cost of Service Surcharge or Credit" allows a utility that pays state franchise taxes, and has not had a rate proceeding in which the effects of House Bill 11 were considered, to charge or credit customers in order to account for this tax change

Top Ten U.S. Cities Rate Comparisons

Figure 3 shows a rate comparison between HL&P and the nine other largest cities (by population) in the U S The figure provides the average total residential cost in cents per kWh That is

Residential Service
Top 10 Cities Rate Comparisons

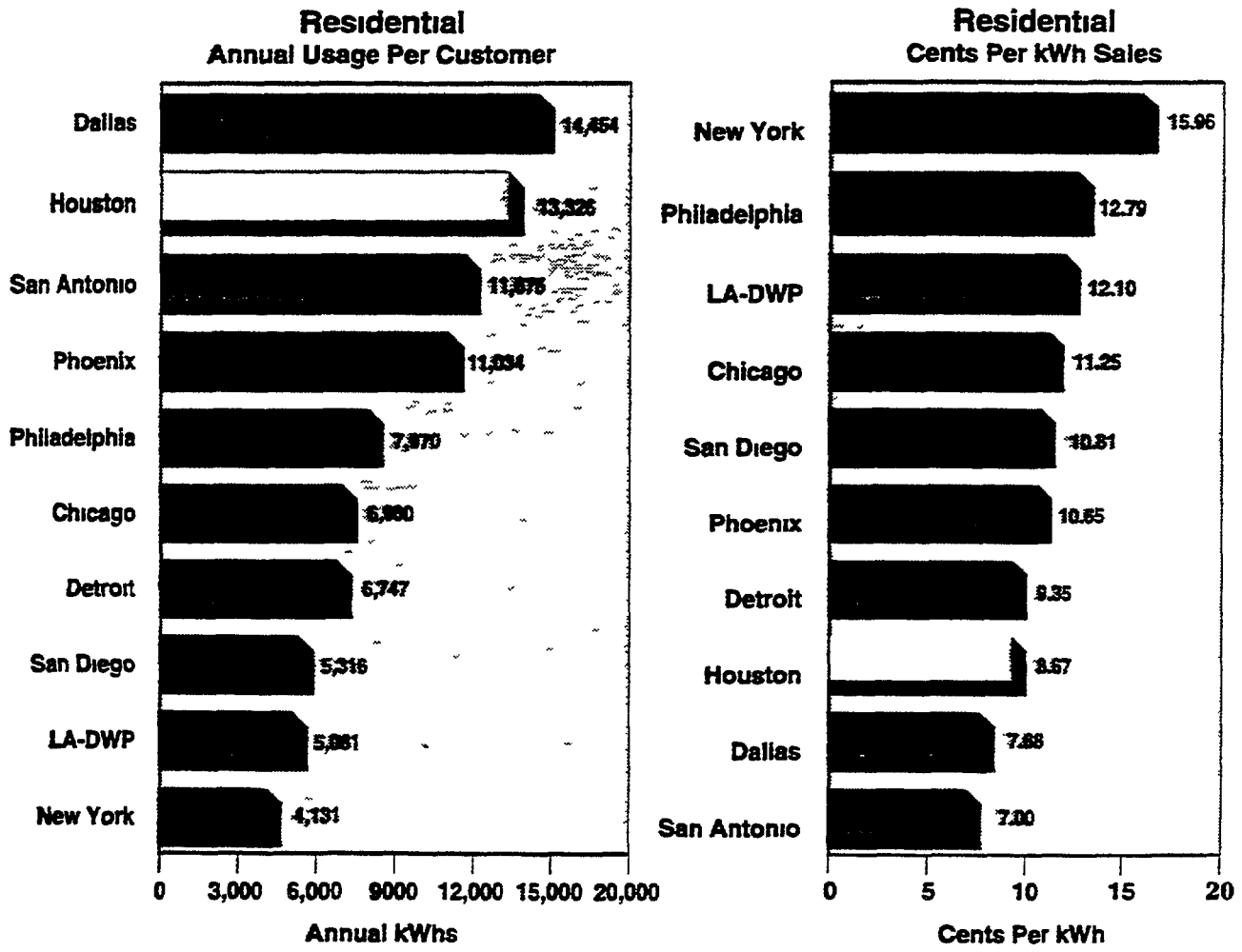

Figure 3

the total annual revenue received by the Company from all residential customers, including fuel, PCRF, and HB 11, divided by the total annual kWh sold to all residential customers Also provided in Figure 3 is the average annual kWh usage of residential customers in these ten largest cities As shown, HL&P's customers pay below the average rate of the top ten U S cities, yet have the next to highest annual kWh usage

RATE DESIGN PROCESS

The rate design process is guided to a great extent by cost data provided in the *Cost of Service Study (COSS)*, also called Cost Allocation Study The cost to serve each rate class, as provided in the COSS, is a primary consideration in the design of the Company's rate structures However, the COSS does not address all areas of consideration in designing rates Rate Design requires judgment and must

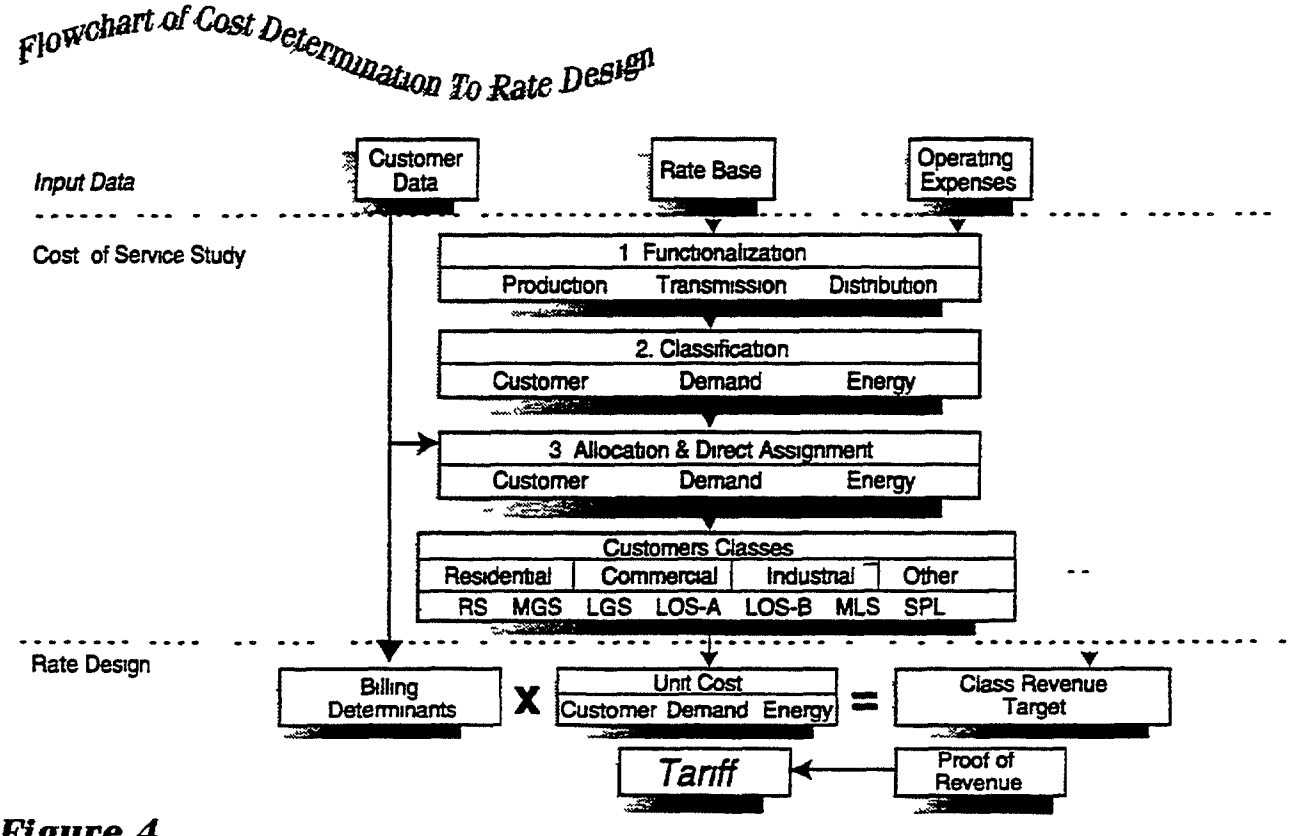

Figure 4

HL&P Electric Service System

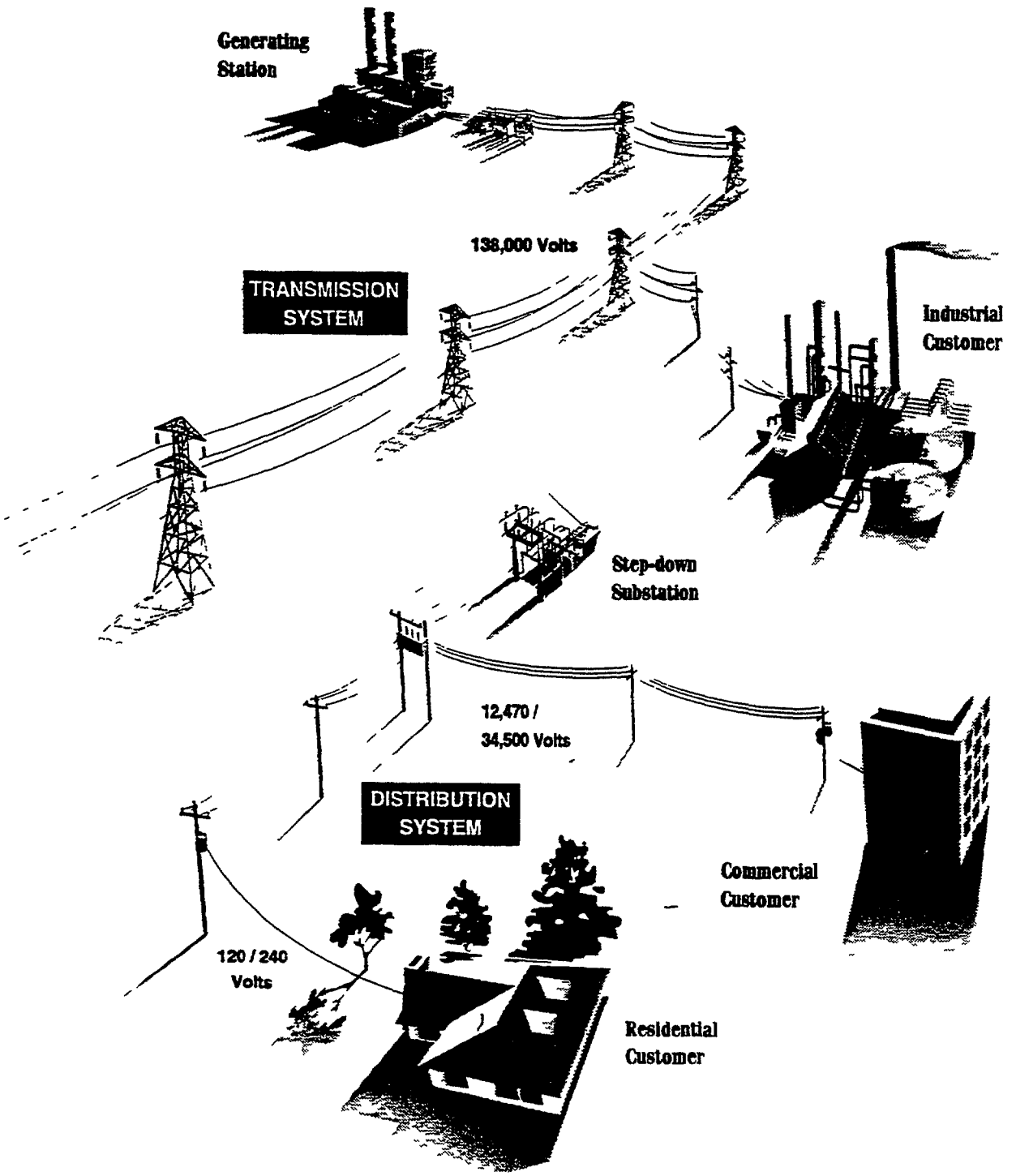

Figure 5

also consider such principles as gradualism, customer acceptance, economic efficiency, administrative feasibility, revenue stability and revenue erosion

Figure 4 shows how customer data, rate base, and Company operating expense data are used in the COSS and in the rate design process in order to develop final rates which support the Company's revenue requirement

Customer data input includes things such as number of customers, coincidence of use (class usage relative to system peak demand) service voltage level, billing demand for those classes where applicable, and energy usage *Rate base* (or invested capital) and *operating expenses* were described earlier *Revenue* includes the income from electric sales plus any additional income from miscellaneous utility sales To perform a COSS the dollar amounts in each category of rate base, operating expenses, and revenue are separated into functions, classified, and allocated or assigned to rate classes

Functionalization involves separating the dollar amounts into three major groupings These primary functions which are directly related to the production and supply of electricity are production transmission and distribution Figure 5 shows a simplified diagram of a utility system and some typical items which would make up these functional areas

The functional classifications are further divided into *classifications* based on the aspect of utility service being provided There are three cost classifications capacity customer, and energy *Capacity* costs are dependent upon the demand or load of the customers Transmission plant, for example, is capacity related since transmission plant is designed for the maximum demand expected on the system *Customer* costs are those costs incurred because of the existence of the customer and do not vary with the demand or energy usage of the customer Meter reading expense is a good example, since the meters are routinely read regardless of the customers demand or energy usage The final classification, *energy*, is volumetric, varying with the amount of electricity a customer consumes An example is fuel expense, since fuel usage is variable and depends on a customer's energy consumption

The next step is the *allocation* or *direct assignment* of the classified costs to the rate classes There are several instances where a determination can be made as to cost causation being specifically attributable to a particular rate class In those cases, costs are directly assigned to the rate class Whenever practical a direct assignment should be made for costs, however, this is not always possible Those costs which are not directly assignable are considered joint costs since

they provide service for more than one class of customer These joint costs must be allocated to rate classes based on cost causative factors (allocation factors) In brief, these allocation factors follow the classified cost where class demands are used to allocate capacity costs, the number of customers per class is used to allocate customer costs, and kWh consumption per class is used to allocate energy related costs

Unit costs are an output of the COSS The unit costs provide, for each rate class, an average rate for each of the three areas of cost classification customer, demand, and energy However, these unit costs cannot be used as the rate design for the rate class because the COSS does not address all the rate design issues necessary for efficient, effective, and equitable rate design The COSS process addresses **inter-class** equity, or equity between classes That is to say, that the COSS seeks to ensure that each rate class fairly pays its share of the Company's overall revenue requirement

The rate design process addresses **intra-class** equity or equity within individual classes The main goal of rate design is to communicate cost and the cost to serve each rate class is a primary consideration in the design of the Companys rate structure However a number of other objectives are important in achieving the main goal in a manner which is equitable within the rate class Other principles considered in the rate design process include

1 *Equity* - Rates should track costs The rate design should recover the costs to serve the rate class and, within the rate class, the rate should track the cost to serve different customer usage patterns

2 *Revenue Stability* - The Company should be reasonably assured of receiving in a consistent manner, the revenue which recovers fixed costs

3 *Revenue Erosion* - Rates should be designed such that events beyond the control of the Company do not seriously erode revenue when there is no corresponding cost of service reduction

4 *Economic Efficiency* - Rates should send cost-effective price signals to the consumer which encourage the efficient use of electricity and the efficient utilization of Company resources

5 *Administrative Feasibility* - Rates should not be overly burdensome to administer and should not be susceptible to frequent misunderstandings or disagreements between the Company and the customer Cost

of administration should not be high in relation to the other costs of service

6 *Customer Acceptance* - The degree of complexity of a rate and the number of options available to each rate class should fit the degree of sophistication of the customers within the rate class Residential and small commercial rates must be clear enough to be understood and accepted by customers who are not trained in the complexities of electric pricing theory On the other hand, customers who can bring sophisticated resources to bear on rate matters may want to deal with complex rates and may need more rate options to gain acceptable solutions to complex energy requirements

7 *Gradualism* - Changes in price of service or other conditions which significantly affect the customer's bill should be made gradually In so doing, stability is maintained and customers are able to plan their activities in a reasonable manner

RESIDENTIAL RATES

The Company's residential rate components are shown in Figure 6 The residential rate has an inverted rate design for the summer months, in that, each succeeding block of kWh usage is charged a higher price per kWh than the previous block However, in the winter months the residential rate has a declining tail-block after 800 kWh of use For usage over 800 kWh, the price per kWh is less than the previous block The winter tail-block benefits higher load factor customers High load factor residential customers are defined as those having more consistent annual usage as demonstrated by the ratio of summer kWh use to winter kWh use Thus for the same summer peak demand the high load factor customer has more annual kWh over which to spread costs Since for residential customers, capacity-related costs are recovered through the kWh charges, it is necessary to have a lower winter tail-block charge to prevent these customers from over-contributing to capacity related costs

Residential Service (RS)

Monthly Facilities Charge	$ [illegible]
Energy Charges ($kWh)- Summer (May-Oct):	
0-250 kWh	.022500
>250 kWh	076518
Energy Charges ($kWh) - Winter (Nov-Apr):	
0-250 kWh	022500
Next 500 kWh	.076518
>800 kWh	044552

Other charges: Fuel Charge, PCRF, Sales Tax

Figure 6 *- RS Rate effective 1-1-95*

The Company has over 1 3 million residential customers Within those customers, the Company has identified four main subgroups with distinct usage patterns They are referred to as

- Small users (contains higher load factor customers)
- Summer/winter peakers (contains higher load factor customers)
- Moderate summer peakers
- Strong summer peakers

COMMERCIAL RATES

Commercial customers generally have a choice of two rate schedules Miscellaneous General Service (MGS) or Large General Service (LGS) Commercial customers range in size from under 10 kVA (kilovolt amperes) to over 1,000 kV For the MGS class, over 40% of the customers are under 10 kVA and are metered with watt-hour meters with no demand registration The commercial customers' consistency of usage, or load factor, varies widely, from a traffic signal which operates 24 hours a day at the same level of usage to an irrigation pump which is used only a few days per year

One of the primary design criterion for commercial and industrial rates is to encourage the improvement of system load factor, so that the Company's utilization of capital and operation of resources are optimized Load factor is a measure of the average rate of usage of electricity (as a percentage) over a period of time compared to the maximum usage that could have occurred over that same time period It is the ratio of actual kWh usage over a certain time period to the maximum usage which could have occurred The formula for load factor is shown below

$$\text{Load Factor} = \frac{\text{Actual kWh Usage For the Time Period}}{\text{Peak kVA} \times \text{Hours in Time Period}} \times 100$$

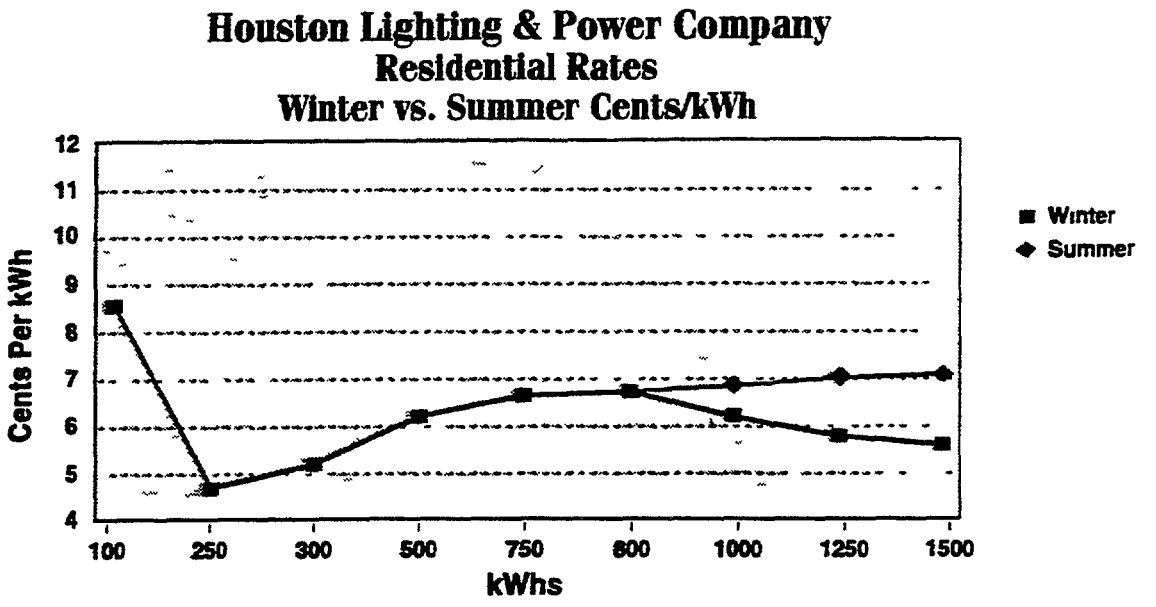

Figure 7 *- Rates effective 1-1-95 (Base rates only, does not include fuel or PCRF)*

The residential rate design incorporates the following factors

- Customer charge is not excessively high (in the mid-range of Texas utilities),
- Benefits low-use/low-income customers without unduly burdening other residential customers through the low charge for the initial 250 kWh block (low use is generally indicative of higher load factor),
- Sends strong summer price signal to encourage energy efficiency (summer tail-block is 3 5 times first block), and
- Declining block winter rate reflects the lower cost to serve high load factor customers off-peak winter load

The table in Figure 7 tracks the average rate per kWh (total bill divided by kWh usage at various levels) for residential customers for both the summer and winter seasons The line representing the average cents per kWh for summer usage shows an increase in cost as usage increases beyond 250 kWh This reflects the increased likelihood that air conditioning load is present and, as usage increases, the greater likelihood that the load will be coincident with the system peak load The line representing the average cents per kWh for winter usage shows a declining cost per kWh after 800 kWh usage This recognizes the need to prevent over-collection of capacity cost from high load factor customers

Why Should MGS Customers Receive a Lower Price Per kWh as Their Load Factor Increases?

Although the MGS rate has a demand charge, the demand charge only recovers approximately 22% of the capacity cost assigned to MGS customers The remainder of the MGS capacity costs are recovered through the energy charges If the kWh charge did not decrease as the load factor increased high load factor customers would over contribute to capacity costs

MGS Rate
Base Dollars per kVA and Cents per kWh vs. Load Factor

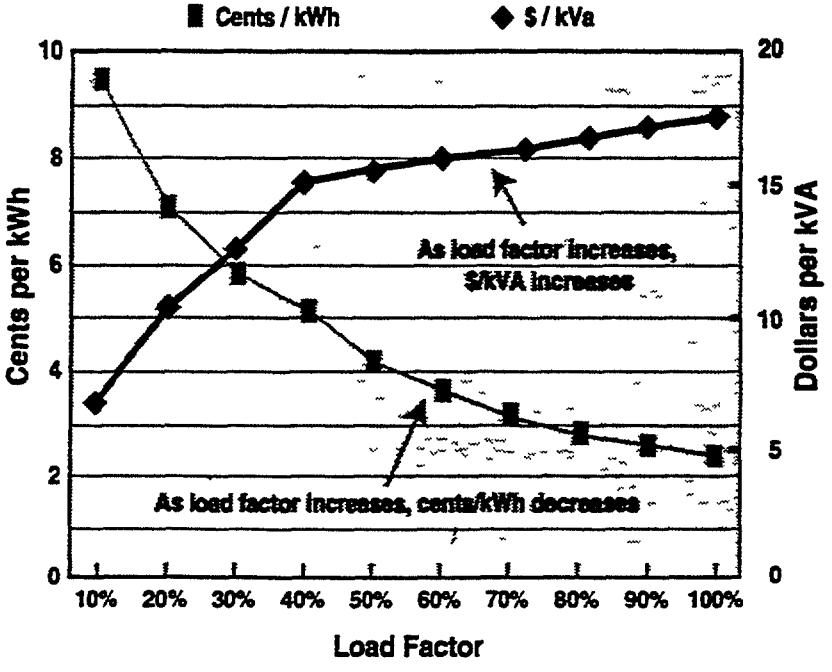

Figure 9 *- Rate Effective 1-1-95 Does not include fuel or PCRF*

What Else Do We Know About Load Factor?

Back in the 1930s, Constantine Bary of Philadelphia Electric Company studied the relationship between load factor and coincidence factor (Coincidence factor is the ratio of load at the time of system or class peak relative to maximum demanc Coincidence factor can apply to an individual customer's load or the load of an entire rate class) In these studies, it was seen that a strong relationship exists between load factor and coincidence factor. Bary found that as d factor increased, the likelihood that a customer's load would be present during the system peak also increased

As discussed earlier, the rate per kWh decreases with increased load factor, however, at the same time the average cost per kVA of demand increases This can be shown by dividing the total monthly bill by the monthly kWh to get an average cost per kWh and then by dividing the total monthly bill by the monthly kVA demand to get an average cost per kVA If these calculations are repeated for the customer's bill but with increased load factor (greater kWh) at the original demand level, the result shown in Figure 9 will be that the average cost per kWh decreases as load factor

Misc. General Service (MGS)

Demand Charge Billing kVA >10kVA ($/kVA)	3.10
Energy Charges ($/kWh) - Summer (May-Oct)	
First 1250 kWhs or 125 kWh per billing kVA	.053274
Next 1700 kWhs or 170 kWh per billing kVA	.032517
Additional kWh	.005750
Energy Charges ($/kWh) - Winter (Nov-Apr)	
First 1250 kWhs or 125 kWh per billing kVA	051587
Next 1700 kWhs or 170 kWh per billing kVA	.032517
Additional kWh	005750

Other charges: Fuel Charge, PCRF, Sales Tax

Figure 8 *- MGS rate effective 1-1-95*

Miscellaneous General Service (MGS)

In the MGS rate, the price signal to improve load factor is given through what is called an expanding block (sometimes called "hours use of demand") rate design. Figure 8 shows the charges for the MGS rate. Notice that the energy charges are given for a fixed number of kWh (e.g., 1250 kWh) and as an "expanding block" (e.g., 125 kWh per kVA). The fixed blocks apply to customers with demands of 10 kVA or less.

For those customers with demands over 10 kVA, the kWh block expands as the kVA increases. For example, the 125 kWh per kVA block includes 12,500 kWh if the demand is 100 kVA (125 x 100 = 12,500) or 25,000 kWh if the demand is 200 kVA (125 x 200 = 25,000). In this way, no matter how large the customer's demand is, a proportional share of kWh is charged at the various expanding blocks. The next expanding block is for 170 kWh per kVA. This second block is for kWh in addition to those paid for in the first block. For the customer in the example above with 200 kVA, this block would be for 34,000 kWh (170 x 200 = 34,000). (The kWh blocks represent the maximum kWh at that block and a customer would only pay for the actual kWh used if that were less.)

The 125 kWh per kVA block is equivalent to a 17% load factor. (125 kWh / 1 kVA X 730 hours in a month = 17%.) The second block of 170 kWh per kVA is equivalent to a total load factor of 40%. ([125 kWh + 170 kWh] / 1 kVA x 730 hours = 40%.) Not only are the MGS blocks expanding, they are also declining blocks. That is, the price per kWh is less expensive in each successive block.

the customer will be billed for, "the primary kVA " First, both an "on-peak kVA" and an "off-peak kVA" are determined for the billing month They are calculated by taking the average of the four fifteen minute periods of highest demand during the month for each respective period The on-peak kVA for the current month and each of the previous eleven months are compared to determine which is the highest value and that is termed the "annual on-peak kVA "

The off-peak kVA is then compared to the annual on-peak kVA If the off-peak kVA is equal to or less than the annual on-peak kVA, then the highest of the following will be billed as the primary kVA

- On-peak kVA,
- Off-peak kVA,
- 85% of the annual on-peak kVA (this is called the "ratchet"), or
- 400 kVA (this is the minimum demand in the rate schedule)

If the off-peak kVA is greater than the annual on-peak kVA, then the annual on-peak kVA will be billed as primary kVA The amount by which the off-peak kVA exceeds the annual on-peak will be billed as "secondary kVA " Secondary kVA is billed at a lower charge than primary kVA

increases and the average cost per kVA increases as load factor increases

The monthly kVA that is used to calculate a customer's bill is determined differently in different rates The billing kVA for MGS customers is based on the average kVA supplied during the 15 minute period of maximum use during the month The billing kVA is not dependent on time of day or on any kVA set in a previous month

Large General Service (LGS)

The LGS tariff is generally applicable to larger commercial customers and medium size industrial customers with demands of approximately 400 kVA or greater Some examples of this type of customer are highrise office buildings, large hotels, hospitals, large schools, and shopping malls Approximately 50% of the demand costs are recovered in the demand charge for the LGS rate The same findings concerning load-factor/coincidence-factor relationship apply to LGS customers just as they do to the MGS customers

Figure 10 contains the charges for the LGS rate schedule The LGS rate introduces some new rate design tools not present in the MGS or RS tariffs LGS contains some time-of-use provisions associated with on-peak and off-peak demand Lower secondary kVA

Large General Service (LGS)

Monthly Facilities Charge	$ 890.00
Demand Charge ($/kVA)	
Primary kVA (min of 400 kVa)	6.27
Secondary kVA	2.20
Energy Charges ($/kWh)	
First 295 kWh per Primary kVA	.025486
Additional kWh	.005000

Other charges. Fuel Charge, PCRF, Sales Tax

Figure 10 *- LGS rate effective 1-1-95*

charges apply to off-peak demand which is in excess of the annual on-peak demand A ratchet provision applicable to billing demand (primary kVA) is also used The ratchet simply states that the customer will not be billed for less than 85% of the highest demand set in the most recent twelve months regardless of actual demand during the month This reduces the effects of wide variations in monthly revenues, sends a price signal to customers to control peak demand, and promotes equity by charging customers based on peak period usage which is generally considered to cause capacity costs to be incurred

For LGS customers several kVA values are calculated in order to determine the kVA that

INDUSTRIAL SERVICE

Industrial customers have two firm rates to select from Large Overhead Service-A and Large Overhead Service-B (LOS-A and LOS-B) Examples of industrial customers are chemical plants and large manufacturing facilities The LOS rates each have a minimum demand requirement of 2,000 kVA, and customers must take service at transmission level voltage These two rates contain a total of approximately 85 customers The LOS classes are a fairly homogeneous group with load factors generally above 40% and minimal seasonal variation LOS customers are also required to contract for electric service with an initial term of five years with a one year cancellation notice

The LOS rates are shown in Figure 11 Since LOS-A customers are somewhat more diverse than LOS-B customers, the LOS-A energy charge is designed to minimize intra-class subsidies The LOS-A energy charge is a three-tiered expanding block rate which includes 30% of the capacity costs

The LOS-B rate has a demand charge which fully recovers capacity costs and an energy charge which only recovers base energy costs The LOS-B rate is designed for customers with an 80% or greater load factor

Large Overhead Service
LOS-A & LOS-B

	LOS-A	LOS-B
Monthly Facilities Charge	$2,634	$2,634
Primary kVA (min 2,000 kVa)	7 11	11 05
Secondary kVA	2.20	2.20
Energy Charges ($Kwh)		
First 295 kWh/kVA	.004874	-
Next 289 kWh/kVA	011071	-
Additional kWhs	005250	-
All kWhs		001194

Other charges Fuel Charge, PCRF, HB11

Figure 11 *- LOS rate effective 1-1-95*

Determination of a customer's primary and secondary kVA for the LOS rates is essentially the same as for LGS customers However, the following differences should be noted

- On the LOS-B rate, there is no annual on-peak kVA, but instead, a contract kVA which is the highest on-peak kVA established during the term of the customer's current contract
- The ratchet in the LOS-A rate is 90% of the annual on-peak kVA
- The ratchet in the LOS-B rate is 90% of the contract kVA

INTERRUPTIBLE SERVICE

Interruptible service provides industrial customers with the opportunity to receive service at a reduced rate, compared to firm service, in return for accepting the risk of having a portion, or all, of their service interrupted All customers benefit from the sale of interruptible power The interruptible customers benefit through lower cost electricity Other ratepayers benefit because the interruptible base revenue is credited to the fuel expense to lower the fuel factor In the case of IS-30 and IS-S the credit to base revenues lowers the revenue requirement of full service customers HL&P also benefits through the right to interrupt these customers during capacity shortfall situations

The first interruptible rate was provided to Dow Chemical Company in the middle 1970s The Company currently has four interruptible rates All the interruptible rates require a minimum energy usage rate of no less than 5,000 kWh per hour

Figure 12 gives some basic information on HL&P's four interruptible rates Interruptible Service-Supplemental (IS-S), Interruptible Service-30-Minute Notice

Interruptible Service

Rate	Notice	Interruptible Hours per Year	Number of Customers	MWs*	¢/kWh
IS-S	30 Mins.	300	6	30	2.89
IS-30	30 Mins	730	6	145	2 42
IS-10**	10 Mins.	8,760	30	1,201	2.24
IS-1**	Instant.	8 760	6	459	2 07

Cents/kWh data based upon 10 MVA, 90% LF customer, rate taken as a supplement.

* Data refelcts year end or December 1994, MWs = max contract kVA.

** Assumes 1 76 cents/kWh for IS-10 and IS-1 estimated fuel rate

Figure 12

(IS-30) Interruptible Service-10-Minute Notice (IS-10) and Interruptible Service-Instantaneous (IS-I) The interruptible rates have varying degrees of interruptibility as reflected in the amount of notice which must be given to the customer before they interrupt and the number of hours in a year that the Company can require the customer to be interrupted As illustrated in Figure 12, the cost of interruptible power is the lowest for customers who can be interrupted the quickest and allow interruptions for the greatest number of hours per year

IS-I load is served through under-frequency relays When system frequency drops below 59 7 hertz, the under-frequency relays instantaneously interrupt the IS-I load IS-I load is the only interruptible load that can be counted toward meeting a portion of HL&P's responsive reserve requirement under the guidelines set by the Electric Reliability Council of Texas (ERCOT)

IS-10 and IS-30 are scheduled loads that can be interrupted with appropriate notice to the customer IS-S is available only as a supplemental rate and is the only interruptible rate available to distribution voltage level customers Unlike IS-10 and IS-30 IS-S load is not required to be scheduled in advance with the Company's Energy Control Center

The interruptible rates encompass a variety of rate designs IS-I and IS-10 customers pay a facilities charge and an energy charge which consists of a fuel charge, a variable O&M expense charge, and a base charge There is no demand charge for IS-I and IS-10 IS-30 customers pay a facilities charge, demand charge, energy charge, and the fuel cost factor, rider FC IS-S customers receive a 40% discount off the demand charge of the firm rate to which IS-S is a supplement

STANDBY SERVICE

Standby service is provided to customers who own and operate their own generation equipment or who purchase electricity from a source other than HL&P such as a third party qualifying facility Standby is essentially "insurance service" in case the customer's primary source of power is not available HL&P offers two types of standby service

(1) Firm (which is divided into backup service and maintenance service) and

(2) Interruptible

Firm standby service is offered under HL&P's Standby Electric Service (SES) rate schedule This service may be taken in conjunction with several other firm or interruptible services or as stand-alone service There are two types of energy charges associated with SES corresponding to backup service and maintenance service The need for backup energy arises when the customer s primary electrical source becomes unavailable due to a forced outage This type of outage is unpredictable and correlates with the reliability of the customer's electrical generating equipment or that of its electrical supplier Backup service is not scheduled and is available to the customer instantaneously on an as-needed basis The customer purchases backup service as an "insurance policy" to guard against damage, both physical and monetary, that an interruption of electrical supply may cause This service, therefore, is very valuable to the customer The value is enhanced further since it is firm service that must be supplied on demand Thus, if a self-generator's unit experiences a forced outage on the afternoon of the peak day of the year, HL&P must plan to have the generation available to meet that customer s demand

Maintenance service on the other hand, is generally predictable and is scheduled well in advance by the customer Maintenance service is required when routine maintenance

is performed on the generating equipment that supplies the customer's electrical power requirements Typically, maintenance is performed once or twice a year and is scheduled during HL&P's off-peak periods The customer must supply advance written notice in order to qualify for this service

The other type of standby service, Interruptible Standby Service (SBI), is offered as a supplemental agreement and must be taken in conjunction with a large overhead service rate or the SES rate SBI may be used during scheduled maintenance outages or during forced outages As with SES, SBI is served instantaneously when needed However, continued use of this service may be temporarily denied or suspended by HL&P when supplying such service threatens the reliability of firm service to the utility's other customers

NEW RATES

In recent months and years, the Company has implemented some new and innovative rates which have expanded the rate options for customers

Residential Service Direct Load Control (Rider RLC)

Rider RLC is the tariff associated with the Energy Partners program This tariff provides our residential Energy Partners with an $8 00 per month credit during the billing months of June through September Energy Partners allow the Company to cycle their air conditioner compressors off for short intervals of time during those hot summer months This allows the Company to reduce the system peak demand which may delay the building of additional generation facilities and reduce the need for future rate increases By 1999 a reduction to peak demand of 150 MW is projected

Figure 13 illustrates how cycling air conditioners can help reduce a customer's demand during the system peak Cycling can occur between the hours of noon and 8 00 p m when the Company's system peak is the highest Although the customer's peak demand may be slightly higher after the cycling is discontinued, the customer's peak has been shifted to a time period when the overall system peak is lower and generating capacity is more readily available to serve the load

Variable Energy Pricing for Residential Service (VEP)

VEP is an experimental rate which is limited to a maximum of 500 customers The tariff was filed and approved in fourteen cities which retain original jurisdiction over HL&P s rates and services Therefore the VEP rate is not available in all parts of our service area

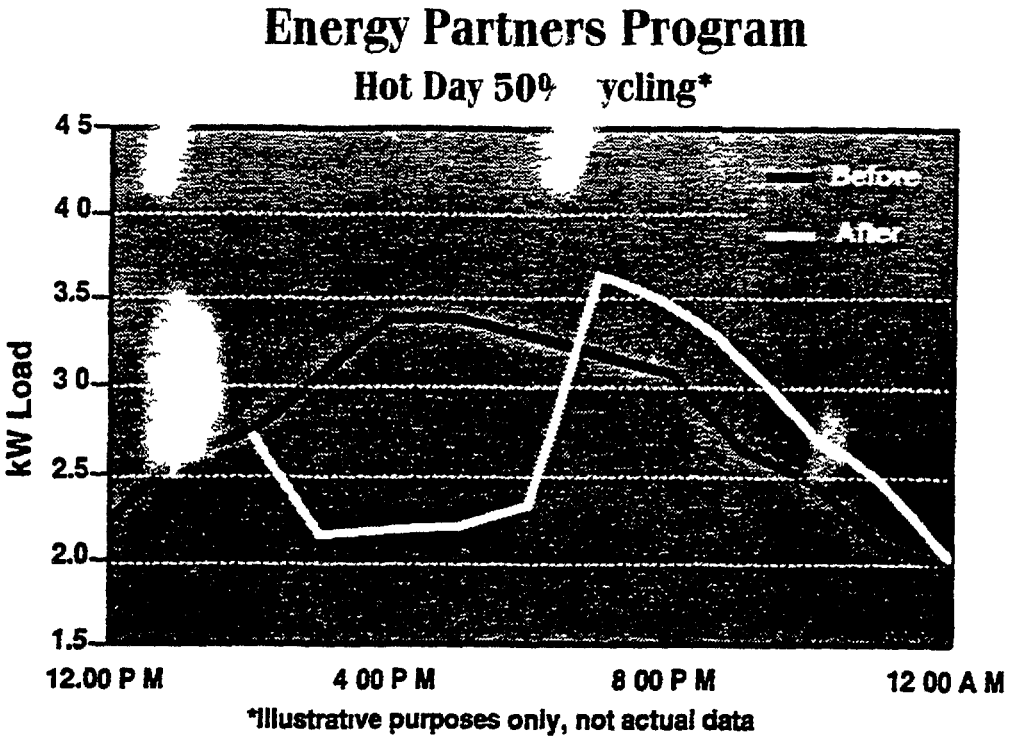

Figure 13

The VEP tariff is part of the Energy Manager pilot program The program will allow participants to respond to varying prices for electricity throughout the day Participants will pre-program intelligent thermostats to automatically respond to pricing signals transmitted by the Com- p y The thermostat can control heating cooling electric water heating, and other major electrical appliances based on the participant's desired comfort level at the various price levels The initial phase of the program will utilize the TranstexT Advanced Energy Mana ement System

Supplemental Agreement for Cool Storage Billing Demand (CSB)

The CSB supplemental agreement is app cable to MGS and LGS customers who use cool storage technology Cool storage technology uses chilled water or ice which is made during the off-peak hours, to cool the facility during the peak hours CSB on-pea ours are 1 p m - 8 p m , Monday throug day, all months of the year (excluding holidays) Figure 14 shows a typical load profile with and without cool storage technology on the CSB rate

Economic Improvement Service (EIS)

The EIS rate is intended to encourage an increase in local employment and stimulate economic activity within the greater Houston area by providing businesses with an additional incentive to locate or expand in the area The local community benefits through increased employment opportunities which strengthen the entire region's economic health Offering an incentive rate that recovers revenues in excess of marginal cost benefits all firm ratepayers, since fixed costs are spread over more sales of electricity This reduces the upward pressure on rates and helps to postpone or lessen future rate increases

Requirements to qualify for EIS include

- The business must have been competitively sited and the EIS tariff must be shown to have influenced the decision to locate or expand in HL&P's service area,
- The customer must receive city and/or county tax abatements and add at least 10 new permanent full-time jobs,

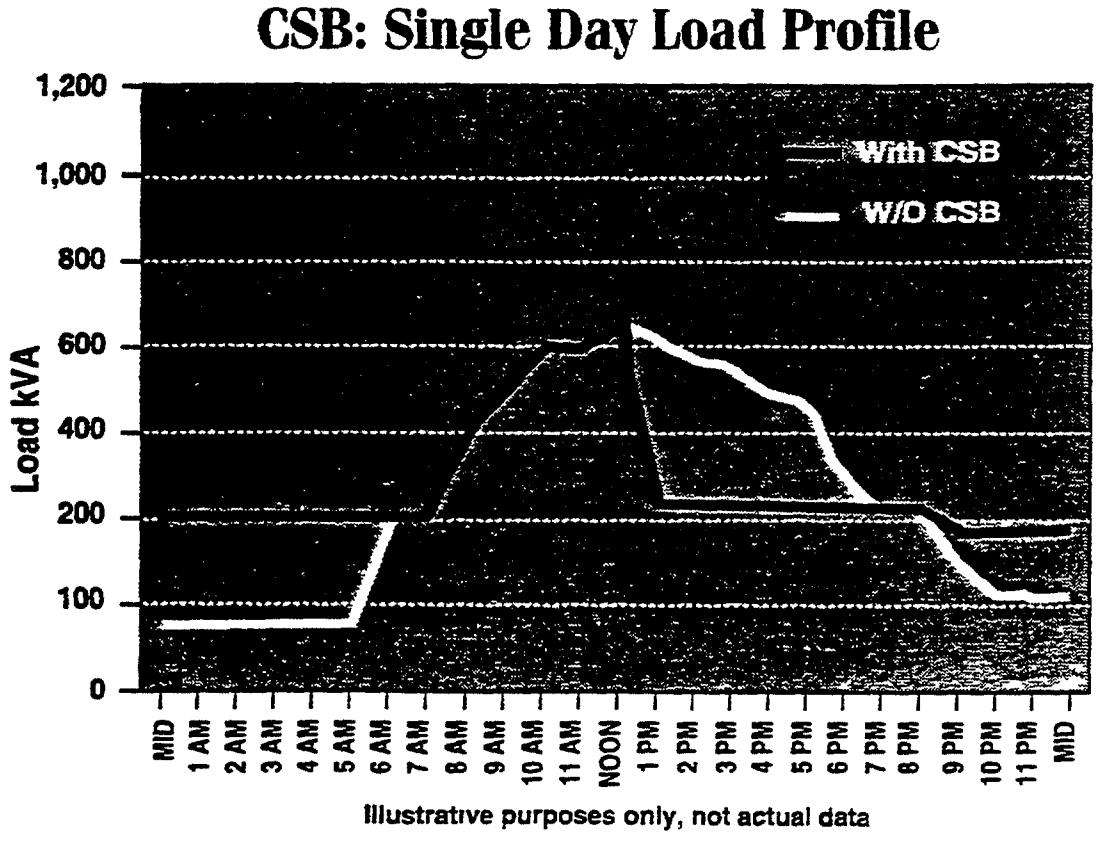

Figure 14

- The customer must allow the Company to perform an energy efficiency analysis for the new or expanded facility,
- The customer must meet certain minimum demand requirements

The EIS tariff requires a five year contract and the tariff will be available for signing-up customers through 1998 The contract requires the customer to be billed on the discounted EIS tariff for the first three years and for the last two years to be billed on one of the Company's standard firm rates (LGS, LOS-A or LOS-B) EIS provides slightly less than a 10% discount on base rates and slightly more than a 5% reduction in total bill as compared to the standard firm rates, averaged over the five year contract period

Special Contract Pricing (SCP)

The SCP tariff is an experimental rate which became effective on June 8, 1995 HL&P proposed this experimental tariff in order to retain customers who, without this tariff would not be on HL&P s system In addition, this rate helps recover revenues in excess of HL&P's marginal cost, and contributes toward the recovery of fixed costs from those customers This experimental tariff will be limited to industrial customers who can demonstrate that they have a viable alternative to HL&P for electrical power at a cost below HL&P's standard firm rates The experimental SCP tariff will allow HL&P the flexibility to negotiate a customer-specific discount which would be in excess of HL&P's marginal cost to serve the customer, but below the otherwise applicable firm rate The contract term cannot be less than five years or more than ten years The SCP rate contains a penalty provision for customers who terminate service before the contract expires The penalty compensates the Company as if service under the SCP rate had never been taken but instead had been taken under another standard firm rate

OTHER REGULATORY MATTERS

Notice of Intent Applications

A Notice of Intent (NOI) application is filed by the Company upon deciding that a new generating plant should be constructed The purpose of a NOI proceeding is to decide the appropriateness of a proposed plant, in light of the alternatives before the Company commits or expends substantial resources on the proposed plant The purpose of a NOI proceeding is not to decide on a specific site or site facilities or whether conservation and alternative energy sources can meet the need Neither is it to determine if the proposed plant is the best and most economical choice of technology available The Company must demonstrate that the need for the proposed plant is consistent with the commission s most recent long-term load forecast and must reasonably evaluate the advantages and disadvantages of the proposed plant and a broad range of alternatives to it The commission will approve the NOI if it concludes that the proposed plant is feasible and reasonable, is compatible with the most recent long-term forecast, and should be given further consideration in light of the alternatives

Certification for New Service Areas and Facilities

A Certificate of Convenience and Necessity (CCN) is generally required for new electric generating units and new electric transmission lines The Company cannot apply for a CCN until it conducts a solicitation for proposals for supply- and demand-side resources that would allow the Company to defer or displace the proposed unit The CCN cannot be filed until after the deadline to respond to the solicitation and after any responses have been evaluated The solicitation shall be based on the unit proposed in the NOI The commission has one year from the date of filing a CCN to approve or deny an application A certificate will be granted by the

commission only after finding that the proposed unit is necessary for the service accommodation convenience or safety of the public

Franchise Agreements

The Company has franchise agreements with the cities within the Company's service territory These agreements contain the terms and conditions for the Company's right to conduct business in the cities In return for the Company's right to conduct an electrical utility business and to construct facilities along public roads the Company pays franchise fees to each city Franchise fees are normally 4% of the gross receipts in a city exclusive of receipts for street lighting received by the Company from its electrical lighting and power sales for consumption within a city However, in certain cities in which the Company only serves a portion of that city, the franchise fee is 2% of the gross revenues collected in that city

The Company has more than 85 franchise agreements The franchise agreement with the City of Houston became effective October 1, 1957, and has a term of 50 years

CONCLUSION

Rate design is an art, not an exact science, and is ever changing and evolving Many changes in the electric utility industry and general changes in the philosophy of utility companies are causing utilities to look at new innovative rate designs as well as re-engineer some old rate designs in order to meet the challenges ahead of them Many times the various objectives a utility is trying to accomplish are conflicting and therefore compromises have to be made

The Company is committed to design innovative and competitive rates to meet the present and future requirements of the Company and its customers HL&P will implement pricing policies that will ensure the optimum use of existing resources thereby maximizing efficiency Rates are seen as an integrated corporate resource which balances the value of service to the customer and the Company

The Company's strategic rate objectives include the following guidelines

- Be competitive Provide options to customers, segment the market, and investigate what the competition is doing
- Be informative Communicate with customers, the PUC, employees, and stockholders
- Provide options Unbundle energy services, and provide service/product differentiation
- Consider customer needs requirements, and wants
- Develop rates that are a Company resource Mesh department and corporate objectives
- Comply with regulatory and legal requirements
- Provide value of service to customer and Company
- Encourage efficiency
- Respond to and/or anticipate market conditions
- Consider social needs and concerns
- Keep rates simple easy to understand and administer

MATERIALS MANAGEMENT

MATERIALS - PURCHASING AND MANAGEMENT

MATERIALS PURCHASING AND MANAGEMENT

- Approved List of Materials
- Inventory System
- Purchase Order System
- Formal Bid Procedures
- Approved List of Vendors
- Vendor Evaluations
- Joint Material Procurement Group

Purchasing and Management Approved List of Materials

- Material Specifications Based on Engineering Needs and Economics
- Material Items Based on Construction Standards
- Consider Climate and Other Environmental Conditions
- Don't Limit To One Manufacturer - Maintain Competition

Purchasing and Management Inventory System

- Material ID Numbers
- Creation of Construction Assemblies
- Major / Minor VS. Full Inventory System
- Importance of Real Time System
- Inventory Counting Cycles
- Re-Order "Tickle" System

Purchasing and Management Purchase Order System

- Requisition Process
- Approval Process
- Issuance of Purchase Orders
- Material ID Numbers
- Received Material VS. Purchased Material
- Payment of Invoices

Purchasing and Management
Formal Bid Procedures

- Establish Bidding Procedures
- Establish Evaluation Procedures
- Blanket Purchases Are Beneficial to Reduce Workload
- Not Always Able to Accept Lowest Bid
- Deliveries Are To Be Considered

Purchasing and Management Approved List of Vendors

- Establish Relationship with Vendors
- Customer Service
- Responsiveness to Problems
- Meeting Delivery Schedules
- Competitive
- Reliable for Emergencies

Purchasing and Management Vendor Evaluations

- Can Be Beneficial If They Are Aware of Evaluations
- Development of Scores or Ranking
- Can Develop Analysis Which Considers Vendor Rank or Score

Share Group Vendor Evaluation

Vendor _____

Sales Representative _____

			Rating
Quality	1	Maintains consistency to standards	_____
	2	Advance notification of process or product changes	_____
	3	Informs of production problems	_____
	4	Convenient and high quality packing	_____
	5	Rectifies rejected material problems	_____
	6	Resolves claims responsively	_____
			_____
Delivery	1	On time delivery	_____
	2	Maintains adequate inventories	_____
	3	Anticipates and notifies of delays	_____
	4	Handles emergency deliveries	_____
	5	Properly labeled and coded products	_____
	6	Shipments are accurate	_____
			_____
Sales /Communication	1	Knowledgeable sales people	_____
	2	Adequate sales contact	_____
	3	Transmits market trends	_____
	4	Relates accurate and timely information	_____
	5	Responds to specific problems	_____
	6	Good follow-through / resolves problems	_____
	7	Informs of internal changes	_____
	8	Prompt response to inquiries	_____
	9	Informs of impending shortages	_____
	10	Informs of new products or processes	_____
	11	Discreet and confidential	_____
	12	Represents product line well	_____
			_____
Cost and Pricing	1	Pricing is competitive	_____
	2	Offers cost reduction suggestions	_____
	3	Adequate notice of price changes	_____
	4	Accurate invoicing and paperwork	_____
			_____
Technical	1	Competent and knowledgeable technical support	
	2	Timely response to technical information requests	
	3	Quality technical literature	_____
	4	Responds to sample request	_____
	5	Assistance to joint development	_____
	6	Assists with environmental compliance	_____
	7	Provides technical know-how and products	_____
	8	Sponsors academic R&D and trade societies	_____
			_____
Supplier Market Position	1	Leading supplier	_____
	2	Large enough to supply long term	_____
	3	Stable management	_____
	4	Committed to R & D efforts	_____
	5	Committed to market	_____
	6	Financially stable	_____
	7	Committed to quality program	_____
	8	Effective hazardous material program	_____
			_____

Rating 5-Excellent 4-Good 3-Average 2-Fair 1-Poor 0-Unacceptable

Completed By _____ Title _____

Co-op _____

Purchasing and Management Joint Purchasing Group

- Find Others With Similar Material Requirements
- Jointly Bid With Total Quantities
- Benefits Include
  - Lower Prices
  - Standardized Material
  - Better Planning
  - Shared Inventories for Emergencies or Shortages

United States
Department
of Agriculture

Rural
Electrification
Administration

Washington
D C
20250

SUBJECT: Long-Range Financial Forecasts of Electric Borrowers Proposed Rule

TO: All Electric Borrowers

FROM: JAMES B. HUFF, SR.
Administrator

Attached for your information and comment is a proposed rule to clarify and revise the requirement that borrowers submit a long-range financial forecast as part of an application for a loan or loan guarantee. Earlier this year, REA published a proposed rule governing lien accommodations and subordinations. Under that rule, a long-range financial forecast will also be required as part of certain applications for a lien accommodation or subordination.

The proposed rule on long-range financial forecasts was published on August 20, 1993. The period for public comments expires on **September 20, 1993.** I encourage all interested parties to submit comments to the address given in the proposed rule.

Attachment

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Proposed Rules

Federal Register
Vol. 58 No 160
Friday, August 20, 1993

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules

DEPARTMENT OF AGRICULTURE

Rural Electrification Administration

7 CFR Part 1710

Long-Range Financial Forecasts of Electric Borrowers

AGENCY Rural Electrification Administration USDA

ACTION Proposed rule

SUMMARY The Rural Electrification Administration (REA) proposes to amend its pre-loan regulations for electric loans to clarify and revise the requirement that borrowers submit to REA a long-range financial forecast as part of an application for a loan, loan guarantee or lien accommodation This proposed rule is intended to strengthen credit practices and to assist borrowers in preparing and REA staff in reviewing loan applications

DATES Written comments must be received by REA or carry a postmark or equivalent by September 20 1993

ADDRESSES. Written comments should be addressed to Sue Arnold, Management Analyst, Program Support Staff U S Department of Agriculture Rural Electrification Administration room 2230-S, 14th Street and Independence Avenue, SW Washington, DC 20250–1500 REA requires a signed original and three copies of all comments (7 CFR 1700 30(e)) Comments will be available for public inspection during regular business hours (7 CFR 1 27(b))

FOR FURTHER INFORMATION CONTACT Sue Arnold Management Analyst U S Department of Agriculture Rural Electrification Administration room 2230-S, 14th Street & Independence Avenue SW Washington, DC 20250–1500 Telephone 202–720–0736

SUPPLEMENTARY INFORMATION

Executive Order 12291

This proposed rule has been issued in conformance with Executive Order 12291 and Departmental Regulation 1512–1 This action has been classified as "nonmajor" because it does not meet the criteria for a major regulation as established by the Executive Order

Regulatory Flexibility Act Certification

The Administrator of REA has determined that the Regulatory Flexibility Act (5 U S C. 601 *et seq*) does not apply to this proposed rule

National Environmental Policy Act Certification

The Administrator of REA has determined that this rule will not significantly affect the quality of the human environment as defined by the National Environmental Policy Act of 1969 (42 U S C. 4321 *et seq*) Therefore, this action does not require an environmental impact statement or assessment.

Catalog of Federal Domestic Assistance

The program described by this proposed rule is listed in the Catalog of Federal Domestic Assistance Programs under number 10 850 Rural Electrification Loan and Loan Guarantees This catalog is available on a subscription basis from the Superintendent of Documents the United States Government Printing Office Washington, DC 20402–9325

Executive Order 12372

This proposed rule is excluded from the scope of Executive Order 12372 Intergovernmental Consultation which may require consultation with State and local officials A Notice of Final Rule titled Department Programs and Activities Excluded from Executive Order 12372 (50 FR 47034) exempts REA electric loans and loan guarantees from coverage under this Order

Executive Order 12778

This proposed rule has been reviewed under Executive Order 12778 Civil Justice Reform If adopted, this proposed rule (1) Will not preempt any state or local laws regulations or policies unless they present an irreconcilable conflict with this rule (2) Will not have any retroactive effect and (3) Will not require administrative proceedings before any parties may file suit challenging the provisions of this rule

Information Collection and Recordkeeping Requirements

The existing recordkeeping and reporting burdens contained in this proposed rule were approved by the Office of Management and Budget (OMB) pursuant to the Paperwork Reduction Act of 1980 (44 U S C. 3501 *et seq*), under control number 0572–0032

Send questions or comments regarding these burdens or any other aspect of these collections of information including suggestions for reducing the burden to the Office of Information and Regulatory Affairs Office of Management and Budget Attention Desk Officer for USDA, Room 3201, NEOB, Washington, DC 20503

Background

REA makes loans and loan guarantees to electric systems to provide and improve electric service in rural areas as authorized by the Rural Electrification Act of 1936 as amended 7 U S C. 901 *et seq* (RE Act) On January 9 1992, at 57 FR 1044 REA published a final rule to add 7 CFR Part 1710 General and Pre-loan Policies and Procedures Common to Insured and Guaranteed Electric Loans. Subpart G of part 1710 codifies the long-standing requirement that all borrowers prepare a long-range financial forecast acceptable to REA as part of an application for a loan or loan guarantee On March 5, 1993, at 58 FR 12552 REA published a proposed rule governing accommodations and subordinations of the government's lien on borrowers systems Under this regulation, a long-range financial forecast will also be required as part of certain applications for a lien accommodation or subordination

According to the terms of the RE Act and REA regulations, REA may make a loan only if the Administrator of REA determines that the security therefor is reasonably adequate and such loan will be repaid within the time agreed OMB Circular No A-129 Policies for Federal Credit Programs and Non-Tax Receivables requires that Federal Agencies prescreen loan applications in order to determine the credit worthiness of the applicant and to prevent future delinquencies A valid determination of an applicant s credit worthiness cannot be made without a long-range financial forecast from the borrower

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REA is proposing to clarify requirements for this forecast Under the current rule the forecast must include a full explanation of the assumptions supporting data, and analysis used (§ 1710 300(c)(4)) The proposed rule will revise this paragraph to clearly set out the items that REA considers necessary components of a full explanation The first item proposed subparagraph (i) the methodology used for the projections, is part of the existing rule The identification of the organization that prepared the forecast and the software used and the sources of significant data inputs proposed in subparagraphs (ii) and (iii) respectively are similar to the kinds of disclosures that appear on historical financial statements. REA believes that this information is necessary to the Agency in evaluating any inadvertent biases in the forecast or any errors inherent in a computer algorithm

Subparagraph (iv) will provide that the borrower include a statement addressing the expected useful life of the facilities to be financed by the proposed loan. Paragraph 1710 115(b) of the existing rule states that REA loans must generally be repaid with interest within a period, up to 35 years, that approximates the useful life of these facilities. In order to determine the composite useful life of these facilities § 1710 115(b) requires that the borrower submit its proposed depreciation rates for these facilities as part of its loan application The proposed new § 1710.300(c)(4)(iv) is simply intended to set forth the specific loan application document and format for this information According to this paragraph the borrower must either (1) certify that at least 90 percent of the loan funds are for facilities that have a useful life of 33 years or longer or (2) submit a schedule showing the costs and useful life of those facilities with a useful life of less than 33 years. Loan maturity will be based on the weighted average of these useful lives.

Since most loans are based on a two-year construction work plan and since exact useful life is difficult to predict, REA will generally add two years to the composite average useful life in order to compute loan maturity In other words if the weighted average useful life of the facilities is 33 years, the maximum allowable maturity for the loan will be 35 years

The provisions in proposed subparagraphs (v) (vi) and (vii) requiring reconciliation of apparent discrepancies or variations in information provided by the borrower in different documents, and between the borrower's historical and projected trends are intended to require that the borrower present to REA comprehensive and consistent information in order to demonstrate that its system is viable and that the proposed loan is financially feasible.

REA is further proposing to clarify and revise the provisions for sensitivity analysis and analysis of alternative scenarios in § 1710 300(d) Under the proposed amendment all forecasts will show as a base case scenario the borrower s estimation of its most probable financial scenario Since unforeseen events often occur certain forecasts will show, in addition a range of less optimistic assumptions for major variables The proposed amendment will retain the current provisions requiring sensitivity analysis for power supply loans that exceed the smaller of 10 percent of the borrower s total utility plant or $25 million

In order to simplify the requirement for distribution borrowers, REA is proposing to amend the existing regulation to require sensitivity analysis for forecasts used in support of loans or loan guarantees that exceed 10 percent of the borrower's net utility plant and if the borrower fails to meet certain tests of financial strength. The tests of financial strength in terms of equity as a percentage of total assets, Times Interest Earned Ratio (TIER), and Debt Service Coverage (DSC) are the same as the criteria that REA proposed in 7 CFR 1717 854 for determining a borrower s eligibility for advance approval of a lien accommodation. REA believes the proposed amendment will require sensitivity analyses only where such analysis is necessary to a determination of loan feasibility Distribution borrowers shall coordinate in advance with the REA General Field Representative so that agreement can be reached on major aspects of the economic studies The proposed rule will further clarify the requirement by listing examples of the kind of analysis that may be required.

REA may require additional analyses in cases where a borrower faces certain specific risks Examples of such risks include potential loss of a large load or annexation of a portion of a borrower s service territory

On the effective date of this regulation the following REA bulletins concerning financial forecasting and planning will be rescinded

105–4 Financial Management

105–5 Financial Forecast—Electric Distribution Systems

105–7 Long-Range System and Financial Planning—Power Supply Borrowers

In addition, REA proposes rescission of REA Bulletin 5–1 Joint Use of Facilities for Telephone and Electric Service This bulletin issued in 1954 and last revised in 1972 deals with agreements between electric and telephone borrowers and with other utilities for joint use of poles The information in the bulletin is obsolete and REA believes guidance from REA in this area is unnecessary in today's technological and regulatory environment In the future borrowers need submit joint use agreements to REA only at REA request.

List of Subjects in 7 CFR Part 1710

Electric power Electric utilities, Loan programs-energy Reporting and recordkeeping requirements Rural areas

For the reasons stated, REA proposes to amend 7 CFR chapter XVII, part 1710 as follows

PART 1710—GENERAL AND PRE-LOAN POLICIES AND PROCEDURES COMMON TO INSURED AND GUARANTEED ELECTRIC LOANS

1 The authority citation for part 1710 continues to read as follows.

Authority 7 U.S C. 901–950(b) Public Law 99–591 Delegation of Authority by the Secretary of Agriculture, 7 CFR 2 23 Delegation of authority by the Under Secretary for Small Community and Rural Development, 7 CFR 2.72.

2 Section 1710 300 is amended by revising paragraph (c)(4) and the introductory text of paragraph (d) adding the word "and" at the end of paragraph (d)(3) removing the words " and at the end of paragraph (d)(4) and adding in their place a period removing paragraph (d)(5), and revising paragraphs (e), and (f) and adding paragraph (g) to read as follows

§ 1710.300 General.

* * * * *

(c) * * *

(4) A full explanation of the assumptions supporting data and analysis used in the forecast, including

(i) The date of the REA approved Power Requirements Study used for load and KWh projections, and the methodology used to project rates revenue power costs, operating expenses plant additions and other factors having a material effect on the financial statements and on financial ratios such as equity TIER, and DSC,

(ii) The name of the organization that prepared the forecast, if the forecast was not prepared by the borrower and the name, version, and release of any software program(s) used,

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(iii) The sources of all data and assumptions for major variables not directly produced by the borrower that materially affect the financial forecast Some examples of such inputs include future cost projections for purchased power provided by a power supplier and load projections from large industrial customers

(iv) Information on the borrower s proposed depreciation rates for the plant additions to be financed by the proposed loan for use by REA in determining loan maturity as required by § 1710 115(b) This information must provide a certification that the proposed depreciation rates fall within the ranges deemed appropriate by REA as set forth in Bulletin 183-1 or its successor and either

(A) If at least 90 percent of the loan funds are for facilities that have a useful l fe of 33 years or longer a certification so stating or

(B) If more than 10 percent of the loan funds are for facilities with a use ful life of less than 33 years a schedule of proposed depreciation rates for those facilities that have a useful life of less than 33 years

(v) A reconciliation of any apparent inconsistencies or differences between the projections shown in the financial forecast and projections contained in other documents submitted by the borrower to REA

(vi) A reconciliation of any apparent inconsistencies or differences between the projections shown in the financial forecast and the borrower s history as shown on its year-end Financial and Statistical Reports or other documents submitted to REA. This historical comparison must cover a period of not less than three years prior to the loan application

(vii) A statement of the borrower s current policy on retirement of capital credits and a discussion of any differences between this policy and the assumptions used for projected retirements and

(viii) Any other information considered by the borrower or by REA to be relevant.

* * * * *

(d) The following plans studies and assumptions shall be used in developing the financial forecast and may be cross referenced as appropriate

* * * * *

(e)(1) The financial forecast shall show, as a base case the most probable scenario based on actual plans of the borrower and most realistic assumptions about the technological business and regulatory environment.

(2) For power supply borrowers in addition to the base case the forecast shall show a reasonable range of assumptions for the major variables to test the sensitivity of the results to changes in assumptions if the financial forecast is used in support of a loan or loan guarantee request that exceeds the smaller of 10 percent of the borrower s total utility plant or $25 million

(3) For distribution borrowers in addition to the base case a forecast used in support of a loan or loan guarantee exceeding 10 percent of the borrower s net utility plant shall show a reasonable range of assumptions for the major variables to test the sensitivity of the results to changes in assumptions unless the borrower meets the conditions set forth in paragraph (e)(3)(i) or (ii) of this section

(i) The ratio of the borrower s equity less deferred debits (expenses) to total assets is at least 40 percent at the time of the loan application and is not less than 37 percent after taking into account the effect of the proposed loan and the borrower has achieved a TIER of at least 1 5 and a DSC of at least 1 25 in each of the 3 calendar years immediately preceding the loan application or

(ii) The ratio of the borrower s equity less deferred debits (expenses) to total assets is at least 35 percent at the time of the loan application and is not less than 32 percent after taking into account the effect of the proposed loan and the borrower has achieved an operating TIER (OTIER) of at least 1 5 and an operating DSC (ODSC) of at least 1 25 in each of the 3 calendar years immediately preceding the request for a loan For the purpose of this paragraph ODSC and OTIER shall be calculated as follows

$$ODSC = \frac{A+B+C}{D}$$

and

$$OTIER = \frac{B+C}{B}$$

where

A = Depreciation and Amortization Expense which equals Part A Line 12 of REA Form 7

B = Interest on Long-term Debt which equals Part A Line 15 of REA Form 7 except that Interest on Long Term Debt shall be increased by 1/3 of the amount if any by which Rentals of Restricted Property (Part M Line 3 of REA Form 7) exceed 2 percent of Total Margins and Equities (Part C, Line 33 of REA Form 7)

C = Patronage Capital and Operating Margins which equals Part A Line 20 of REA Form 7 and

D = Debt Service Billed (REA + Other) which equals all interest and principal billed during the calendar year plus 1/3 of the amount, if any by which the rentals of Restricted Property (Part M Line 3 of REA Form 7) exceeds 2 percent of Total Margins and Equities (Part C, Line 33 of REA Form 7)

(4) REA may on a case by case basis require additional sensitivity analysis or other information or tests if REA determines that such analyses are necessary to make a determination of the feasibility or security of the proposed loan

(f) The financial forecast shall use the accrual method as approved by REA for analyzing costs and revenues and as applicable compare the economic results of the alternatives on a present value basis

(g) REA may obtain and review commercially available credit reports on applicants for a loan or loan guarantee to verify income assets and credit history, and to determine whether there are any outstanding delinquent Federal or other debts Such reports may also be reviewed for parties that are or are proposed to be joint owners of a project with a borrower or for parties that are or are proposed to be large consumers of a borrower

3 Section 1710 301 is amended by removing the word and at the end of paragraph (b)(2) removing the period at the end of paragraph (b)(3) and adding in its place the words and" and adding a new paragraph (b)(4) to read as follows

§ 1710.301 Financial forecasts—distribution borrowers.

* * * * *

(b) * * *

(4) Include sensitivity analysis if required by REA pursuant to § 1710 300(e)(3) The borrower shall coordinate in advance with REA concerning the scope of the sensitivity analysis and the variables to be tested Examples of sensitivity analysis that might be used are

(i) Effects of a 100 to 200 basis point increase in the financing interest rate

(ii) Effects of power costs 10 percent above the cost projected in each year of the base case scenario

(iii) Effects of a 50 percent reduction in the annual rate of projected load growth

(iv) Effects of loss of a large load

(v) Effects of annexation of a portion of the borrower s service area and

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(vi) Effects of a 20 percent or more increase in construction costs

Dated August 9 1993

Bob J Nash,

Under Secretary Small Community and Rural Development.

[FR Doc 93–20110 Filed 8–19–93 8 45 am]

BILLING CODE 3410–15–F

United States
Department
of Agriculture

Rural
Electrification
Administration

Washington
D C
20250

August 29, 1986

SUBJECT 7 CFR Part 1709

TO All Electric Borrowers

Attached is a copy of the proposed 7 CFR Part 1709, "Criteria for the Development, Approval and Use of Power Requirements Studies Prepared by REA Borrowers," dated May 21, 1986, for your information and comments CFR is the abbreviation for the Code of Federal Regulations This document was published in the Federal Register on August 11, 1986 The official comment period expires October 10, 1986

Charles R Miller

CHARLES R MILLER
Assistant Administrator - Electric

Attachment

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Rural Electrification Administration

7 CFR Part 1709

Criteria for the Development, Approval and Use of Power Requirements Studies Prepared by REA Borrowers

AGENCY: Rural Electrification Administration

ACTION. Proposed rule

SUMMARY The Rural Electrification Administration (REA) proposes to amend 7 CFR 1700 by adding part 1709—PRIMARY SUPPORT DOCUMENTS subpart A—Power Requirements Study, sections 1709 1–1709 6 The proposed rule will set forth the rules and procedures to be followed by REA and its borrowers for the development, approval and use of Power Requirement Studies (PRS) Currently this material is set forth in REA Bulletin 120–1 'Development, Approval and Use of Power Requirements Studies" The primary purposes of this proposed rulemaking action are to (1) codify the regulations, (2) eliminate reference to the suggested procedure set forth in the Appendix to Bulletin 120–1 and (3) reduce Federal regulations This proposed rule will impact only REA electric program borrowers

DATE: Public comments must be received no later than October 10 1986

ADDRESS Submit written comments to Archie W Cain, Director, Electric Staff Division Rural Electrification Administration, Room 1246 South Building U S Department of Agriculture Washington DC 20250–1500 All written submissions made pursuant to this action will be made available for public inspection during regular business hours at the above address

FOR FURTHER INFORMATION CONTACT: Georg A Shultz, Chief, Energy Forecasting Branch Electric Staff Division at the above address telephone number (202) 382–1920 The Draft Impact Analysis describing the options considered in developing and implementing the proposal is available on request from the above office

SUPPLEMENTARY INFORMATION: Pursuant to the Rural Electrification Act, as amended (7 U S C 901 et seq , 1921 et seq) (Act) REA proposes to amend its policy as set forth in REA Bulletin 120–1, 'Development Approval and Use of Power Requirements Studies"

This proposed action has been reviewed in accordance with Executive Order 12291, Federal Regulation. It will not (1) have an annual effect on the economy of $100 million or more, (2) result in major increases in costs or price for consumers, individual industries, Federal, State or local government agencies or geographic regions or (3) result in significant adverse effects on competition employment investment or productivity and therefore has been determined 'not major

This action does not fall within the scope of the Regulatory Flexibility Act REA has concluded that promulgation of this rule would not represent a major Federal action significantly affecting the quality of the human environment under the National Environmental Policy Act of 1969 (42 U S C 4321 *et seq* (1976))

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and therefore does not require an environmental impact statement or an environmental assessment This is listed in the Catalog of Federal Domestic Assistance under No 10 850 Rural Electrification Loans and Loan Guarantees For the reasons set forth in the final rule related notice to 7 CFR 3015 subpart V in 50 FR 47034 November 14 1985 this program is excluded from the scope of Executive Order 12372 which requires intergovernmental consultation with State and local officials

Background

The purpose of the present bulletin and the proposed rule is to provide the borrower and REA with the best information available on future electric power requirements of Rural Electrification Act beneficiaries The proposed rule permits each borrower to determine the most appropriate method for developing its PRS When making this determination, the borrower must consider its individual needs and resources as well as Rural Electrification Act requirements REA recognizes that load projections are based on specific assumptions available data, available resources and available methodology at the time the PRS is developed.

Section 1709 5 requires power supply borrowers and their members to develop a PRS Work Plan (PRS Work Plan is defined in text of Proposed Rule) This Work Plan once approved by REA becomes mandatory procedure for the power supply borrower and its members

Each member system of a power supply borrower shall participate in the development of its power supplier s PRS Work Plan and PRS The power supplier s PRS must include a PRS for each member system The member system PRS after approval by REA will be acceptable to REA as support for the member s request for REA financial assistance

Distribution borrowers which are not members of a power supply borrower are exempt form § 1709 5

Distribution borrowers not subject to section 1709 5 must support their choice of procedure in their PRS Each such borrower is to formally apprise REA of its decision prior to committing significant time and resources to its PRS

List of Subjects in 7 CFR 1709

Administrative practices and procedures Electric utilities Loan programs—Energy

In view of the above 7 CFR 1700 is amended by adding a new Part 1709 Primary Support Documents Consisting of Subpart A—Power Requirements Studies to read as follows

PART 1709—PRIMARY SUPPORT DOCUMENTS

Subpart A—Power Requirements Studies

Sec.
1709 1 General
1709.2 Definitions
1709 3 Basic policies
1709 4 PRS for distribution borrowers
1709 5 PRS for power supply borrowers and their members
1709 6 Basic criteria for REA approval of a PRS

Authority 7 U S C 901 et seq., 7 U S C 1921 et seq

Subpart A—Power Requirements Studies

§ 1709 1 General.

This subpart sets forth the policies procedures and criteria for the development, approval and use of Power Requirements Studies satisfactory to REA as prepared by electric borrowers

§ 1709.2 Definitions.

(a) 'PRS means Power Requirements Study or Power Requirements Studies A Power Requirements Study is the study of an electric borrower s electric system loads its service area, its members its cost of electric service and the past present, and future of the economic outlook of its service area in order to obtain valid estimates of the borrower s future electric system loads

(b) 'PRS Work Plan is the plan of work to be used by a borrower in the development of its PRS

§ 1709.3 Basic policies.

(a) *Prerequisite for financial assistance* An REA-approved PRS is a prerequisite for REA approval of an electric borrower s request for loans loan guarantees or other financial assistance pursuant to the Rural Electrification Act. The PRS shall be used in engineering environmental and financial studies relating to major requests for financial assistance from REA

(b) *Current information* A PRS approved and updated within the previous 12 months is normally considered current by REA for the purposes of supporting a request for financial assistance

(c) *Responsibility for studies* Each electric distribution borrower and each power supply borrower is responsible for developing and maintaining a valid and current PRS for its system

(d) *Coordination of studies* Power supply borrowers and their members shall coordinate the development and maintenance of their respective PRS as well as the PRS Work Plan discussed in section 1709.5

(e) *Consistent forecasts* Any PRS submitted to REA shall be consistent with other forecasts that the borrower is required to develop for state or Federal regulatory bodies

(f) *Borrower determines method* Each borrower shall consider its individual needs and resources when developing or adopting a method for its PRS REA recognizes that load projections are based on specific assumptions available data, industry-accepted methodologies and other resources at the time the PRS is developed

(g) *Load management.* All reasonable electric utility industry accepted load management techniques must be evaluated to estimate how they could influence the use of electricity by resulting in the reduction of peak demand improving load factors or otherwise help to utilize resources to best advantage consistent with sound economies and acceptable standards of service See REA Bulletin 140–1 Load Management Programs

§ 1709 4 PRS for distribution borrowers.

(a) *General* This section sets forth the requirements for the development and maintenance of PRS for electric distribution borrowers The requirements of this section apply to all electric distribution borrowers regardless of their source of power supply

(b) *Purpose of a distribution borrower's PRS* A distribution borrower s PRS is the study of the borrower s past and present electric system loads its service area its members its costs and the economic outlook of its service area to (1) Determine what factors influence the borrower s electric system kW and kWh requirements and (2) develop valid estimates of the type and magnitude of the borrower s future electric system loads in terms of the number of consumers served and their kWh usage by class as well as system kW demand for each of the next 10 years

(c) *Use of study* The distribution borrower s PRS shall be used in

(1) Engineering studies of the borrower s existing and planned electric system

(2) Studies of the borrower s existing and planned loan management program

(3) Present rate analysis and future rate studies

(4) Financial forecasts and

(5) Loan feasibility studies

The distribution borrower s PRS shall also be used by the power supply

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borrower of which it is a member in the development of the power supply borrower s PRS

(d) *Basic components of a distribution borrower s PRS* (1) Evaluation of the personnel data processing data and methodology resources available The evaluation shall consider both internal and external resources

(2) Advise REA of the time and resources the borrower will use in the development of the PRS

(3) Analyses of the borrower s electric system loads service area members and cost of electric service adjusted for weather conditions economic conditions and load management programs as appropriate

(4) Development of the assumptions and forecasts using the judgment and knowledge gained through (i) an intimate familiarity with the subject system (ii) general experience and (iii) external inputs as appropriate

(5) Subject assumptions to rigorous sensitivity tests

(6) Establishment of a sound basis for the tracking and evaluation of the PRS

(e) *Documentation* The PRS shall include (1) A discussion that describes the resources available to the borrower and how those resources were utilized in the preparation of its PRS Resources which must be discussed include data availability data processing equipment and programs qualified personnel and managerial inputs among others

(2) A discussion that describes and explains the analysis of the borrower s electric system loads and other pertinent information. Maps shall be used whenever practical in descriptions of the service area s geography and land use Graphs and spreadsheets of all tabular data considered in the analysis such as 120 months of the data now reported on REA Form 7 part R as well as weather economic demographic and power cost data shall be included Revenues must be adjusted for economic conditions All sources of data and information must be clearly identified and dated in this discussion

(3) A discussion that describes and explains all assumptions and other considerations including load management considerations as well as the methods and procedures used to develop future electric system load projections The addition or cancellation of a major capital project by a borrower s power supplier will normally have a significant effect on wholesale and retail rates or revenue requirements Therefore sensitivity analyses reflecting these possibilities shall be included When power is purchased from an REA-financed power supplier the power supplier s most recent forecasted rates or revenue requirements for wholesale power must be used The assumptions used in the forecast of rates or revenue requirements for wholesale power must be discussed regardless of power supplier

(4) A graphical and spreadsheet presentation of the estimated high most probable and low power requirement scenarios by usage classifications and system totals High and low scenarios are necessary to take into account the variability of weather although other factors may also need to be considered as determined by the borrower or REA

(5) A summary of the results on REA Forms 341 and 345 These forms are available on request from REA

(6) A recommendation as to how the borrower s future PRS could be improved through the use of improved resources data collection and coordination with its power supplier

(7) Establishment of procedures which will provide a sound basis for the tracking and evaluation of the PRS

(8) A discussion of borrower s coordination with REA and its power supplier If a borrower is a member of a power supply borrower the member must send the power supply borrower monthly load data as it becomes available REA Form 7 may be used for this purpose The borrower shall participate in workshops and meetings with the power supplier concerning PRS

(9) Rural Electrification Act (RE Act) beneficiary and non-RE Act beneficiary loads must be identified and catalogued

(10) Approval of the PRS by the borrower s Board of Directors

§ 1709 5 PRS for power supply borrowers and their members

(a) *General* This section sets forth the requirements for the development and maintainance of PRS for power supply borrowers and their members Power supply borrowers shall annualy provide REA with a PRS which meets the conditions and terms of this section

(b) *Purpose of Power Supply Borrower s PRS* A power supply borrower s PRS is the study of the borrower s past and present electric system loads its service area its members and the economic outlook of its service area to (1) determine what factors influenced those electric system loads and (2) develop valid estimates of future electric system loads in terms of system total each member system ultimate consumer classifications and ultimate consumer for each of the next 15 years

(c) *Use of study* The power supply borrower s PRS shall provide a basis for engineering studies of the existing and planned generation transmission and load management systems rate analysis financial studies and forecasts risk analyses and loan feasibility studies The power supply borrower s PRS shall also be used by its members in the development of the members' PRS

(d) *PRS work plan* Each power supply borrower shall prepare a PRS Work Plan which recommends the procedures for the development, approval and use of the PRS for its service area The PRS Work Plan establishes the criteria resources method, and schedule required for the preparation of PRS satisfactory to the power supply borrower its members and REA This work plan shall be approved by the power supply borrower s Board of Directors before submittal to REA for final approval

(1) The power supply borrower shall make available in formats acceptable to REA all documents, information data working papers and other documentation which REA may deem necessary for review and approval of the power supply borrower s PRS Work Plan as well as its PRS

(2) Formal REA review and approval of a power supply borrower s PRS will normally begin only after the PRS Work Plan has been approved by the borrower s Board of Directors and REA Amendments to the Work Plan can be made by the borrower at any time subject to REA approval REA is under no obligation to accept or continue to accept a PRS Work Plan that has been previously approved if the PRS Work Plan did not produce a valid PRS as determined by REA

(3) Power supply borrowers shall design their PRS Work Plan to

(i) Produce a valid and fully-documented PRS every year considering such factors as the cost of electric service to the consumer economic conditions and system weather sensitivity as well as including an evaluation of past and future kWh and kW demand in its service area and past and future load management programs among others The PRS must use completely valid accessible and verifiable techniques such as econometric and end-use modeling or a combination thereof

(ii) Provide for distribution and power supply member input and concurrence

(iii) Provide for an interactive and ongoing REA review of the process during the development of the PRS

(iv) Provide for improvement of future PRS by developing improved resources and data collection

(v) Include periodic consumer surveys coordinated with its member systems to

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provide data regarding appliance and equipment saturation and use Surveys of each member system shall be conducted as a block at least every 3 years

(vi) Provide for a sound basis for annually tracking and evaluating the PRS by the power supply borrower its members and REA

(e) *Coordination between power supply borrowers and their members* Each member system of a power supply borrower shall participate in the development of the PRS Work Plan and the power supply borrower s PRS The power supply borrower shall provide certification of such participation and other coordination activities A PRS of a distribution borrower developed in conformance with an REA-approved PRS Work Plan shall be used as support of the distribution borrower's request for REA financial assistance subject to an independent REA review and approval of the distribution borrower s PRS

(f) *Special waiver* REA may grant a waiver of all or part of this subpart on a case-by-case basis if in its judgment, such a waiver is warranted Such a waiver must be requested by the borrower s Board of Directors with adequate supporting documentation to thoroughly identify the specific circumstances which have caused the request.

§ 1709 6 Basic Criteria for REA Approval of a PRS.

This section sets forth the basic criteria for REA for approval of a PRS for a distribution or power supply borrower

(a) The PRS has objectively taken into consideration all relevant factors that impact the consumption of electricity and demonstrates an in depth knowledge and understanding of those factors

(b) The PRS includes an estimate of the accuracy and the range of possible outcomes as well as identifying the most probable outcome

(c) The borrower s top management is thoroughly familiar with the development and preparation of the PRS including its assumptions and can support and defend it responsibly

(d) A sound basis for the tracking and evaluation of the PRS is included to determine if the PRS Work Plan should be revised.

(e) A sound basis exists for the collection of relevant data for future PRS

(f) The PRS accurately identifies Rural Electrification Act beneficiary needs and non-RE Act beneficiary needs

(g) The borrower has used sufficient and reasonable resources assumptions and methods to develop an adequate study The PRS is adequately documented to allow for a thorough and independent review

(h) The PRS of a power supply organization and its members were effectively coordinated and each includes input from consumer surveys coordinated by the power supplier This paragraph applies only if the power supply organization is an REA borrower

(i) The PRS has been approved by the borrower s Board of Directors

Dated May 21 1986

Harold V Hunter,

Administrator

[FR Doc. 86-18012 Filed 8-8-86 8 45 am]

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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

BULLETIN 1767B-3

SUBJECT: Preparation and Use of the RUS Form 254, Construction Inventory

TO: All Electric Borrowers
RUS Electric Staff
Borrower Accounting Division

EFFECTIVE DATE: Date of Approval

EXPIRATION DATE: Four years from effective date

OFFICE OF PRIMARY INTEREST: Borrower Accounting Division

PREVIOUS INSTRUCTIONS: This Bulletin, together with RUS Bulletin 1767B-2 replaces RUS Bulletin 184-2, Suggested Work Order Procedure for Electric Borrowers of the Rural Utilities Service.

FILING INSTRUCTIONS: This is a new bulletin that should be filed with 7 CFR Part 1767. This bulletin is available on REANET

PURPOSE: To provide a uniform system of accounting for amounts due contractors and for additions to and retirements of electric plant resulting from labor and material contracts.

Administrator

12/21/94
Date

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side.

SHEET 1 OF 10 SHEETS

DATE: April 1, 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: Reo Construction Company

AMOUNT PAYABLE TO CONTRACTOR

A. TOTAL COST OF STANDARD, NEW AND CONVERSION ASSEMBLY UNITS INSTALLED *(Total Column 6, RUS Form 254a)*		$391,802.75
B COST TO REMOVE "T" UNITS *(Total Column 7 RUS Form 254a)*		56,382.21
C. AMOUNT TO BE CREDITED TO CONTRACTOR FOR MATERIALS REMOVED FROM EXISTING FACILITIES AND RETURNED *(Total Column 14, RUS Form 254b)*		66,602.74
SUBTOTAL		$514 787 70
DEDUCT		
D AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLY UNITS REMOVED *(Total Column 9, RUS Form 254a)*	$101 040.35	
E. NET AMOUNT OF OWNER–FURNISHED MATERIALS *(Total Column 24, RUS Form 254c)*	131,870 97	$232,911.32
F NET AMOUNT DUE CONTRACTOR *(In making final payment to Contractor, the net amount due the Contractor, as shown by this Certification, will be reduced by the sums, if any, due the Owner for liquidated damages, payment made to date, or other sums which the Owner has the right to retain under the terms of the Contract, and signature by all parties does not preclude the retention by the Owner of such amounts.)*		$281,876.38

CERTIFICATE OF ENGINEER

I certify that to the best of my knowledge and belief the attached final inventory correctly shows the total number and character of assembly units installed and removed by the Contractor and that the net amount of $281,876.38 due the Contractor as shown above, is true and correct.

ENGINEER

DATE By

ACCEPTANCE BY OWNER

OWNER

By PRESIDENT

ACCEPTANCE BY CONTRACTOR

FIRM

DATE By

RUS FORM 254 facsimile–computer generated form

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Account 232, Accounts Payable

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Contractor's Invoice	8 4		448,184 96		448,184 96
	Contractor Payment	8.5	419,997.33			28,187 63
	Contractor Payment–Retainage	8.5	28,187 63			0.00

Account 583, Overhead Line Expenses

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Labor–Special Equipment	8 7	22,673 68		22,783 68	

8.18 The following exhibits provide the basis upon which the preceding journal entries were based:

8.18.1 Exhibit A RUS Form 254, Construction Inventory
8.18.2 Exhibit B RUS Form 254a, Construction Inventory
8.18.3 Exhibit C RUS Form 254b, Construction Inventory
8.18.4 Exhibit D RUS Form 254c, Construction Inventory
8.18.5 Exhibit E Schedule of Special Equipment Reused
8.18.6 Exhibit F Table D - Value of Material Items Creditable to Bidder
8.18.7 Exhibit G Retirement Work Order
8.18.8 Exhibit H Unitization and Distribution to Plant Accounts
8.18.9 Exhibit I RUS Form 219, Inventory of Work Orders

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Account 108 8, Retirement Work in Progress

Date	Description	Reference	Debit	Credit	Debit	Credit
	Labor–Plant Removal	8	48,561 02		48,561 02	
	Material Removed–Contractor	8 11		101,040 35		52,479.33
	Material Removed & Returned	8 11	66,602 74		14,123 41	
	Material Salvaged	8 11		7,650 78	6,472 63	
	Speical Equipment–Reused	8 12	28,440.27		34,912 90	
	Original Cost of Plant Retired	8 14	68,948 63		103,861.53	
	Net Loss Due to Retirement	8 15		103,861.53	0 00	

Account 131, Cash

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Contractor Payment	8.5		253,688 75		253,688 75
	Contractor Payment–Retainage	8.5		28,187 63		281,876.38
	Indirect Costs–Noncontract	8 9		36,720 88		318,597.26

Account 143, Other Accounts Receivable

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Material Furnished to Contractor	8.3	135,244 84		135,244 84	
	Material–Contractor's Invoice	8.5		166,308.58		31,063 74
	Material Adjustment	8 6		5,274.38		36,338 12
	Special Equipment–Contractor	8 7	12,179.26			24,158 86
	Mater Unused & Returned	8 10		10,278 75		34,437 61
	Mater Removed–Contractor	8 11	101,040.35		66,602 74	
	Material Removed & Returned	8 11		66,602 74	0 00	

Account 154, Plant Materials and Operating Supplies

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Material Furnished to Contractor	8.3		135,244 84		135,244 84
	Material Unused & Returned	8 10	10,278 75			124,966 09
	Material Salvaged	8 11	7,650 78			117,315.31

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8.16 Journal entry discussed in Section 6.6.6:

Dr. 364, Poles, Towers and Fixtures	$129,504.58	
Dr. 365, Overhead Conductors and Devices	237,609.12	
Dr. 367, Underground Conductor and Devices	2,281.54	
Dr. 368, Line Transformers	896.85	
Dr. 369, Services	7,111 89	
Dr. 371, Installations on Customers' Premises	922.01	
Cr. 106, Completed Construction not Classified		$378,325.99

To reclassify electric plant in service to the primary plant accounts based upon the "Unitization and Distribution to Plant Accounts" (Exhibit H).

8.17 General Ledger Summaries:

Account 106, Completed Construction Not Classified

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Contract Closing–Construction	8 13	378,325 99		378,325 99	
	Transfer to Plant in Service	8 16		378,325 99	0 00	

Account 107 1, Construction Work in Progress – Contract

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Contractor's Invoice	8 4	448,184 96		448,184 96	
	Material Adjustment	8 6	5,274.38		453,459.34	
	Special Equipment–Contractor	8 7		12,179.26	441,280 08	
	Labor–Special Equipment	8 7		22,673 68	418,606 40	
	Labor–Plant Removal	8 8		48,561 02	370,045.38	
	Indirect Costs–Noncontract	8 9	36,720 88		406,766.26	
	Special Equipment–Reused	8 12		28,440.27	378,325 99	
	Contract Closing–Construction	8 13		378,325 99	0 00	

Account 108 6, Accumulated Provision for Depreciation of Distribution Plant

		Entry			Balance	
Date	Description	Reference	Debit	Credit	Debit	Credit
	Net Loss Due to Retirement	8 15	103,861 53		103,861.53	

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8.15 Journal entry discussed in Section 5.4.4:

Dr. 108.6, Accumulated Provision for Depreciation of Distribution Plant	103,861.53	
Cr. 108.8, Retirement Work in Progress		103,861.53

To record the net loss on plant retired from service. The net loss on plant retired from service is calculated by adding the original cost of the property retired plus the cost of removal and deducting salvage. In the case study, the net loss on retirement is calculated as follows:

Original cost of property retired	$ 68,948.63
Plus: Cost of removal (See Section 8.7)	48,561.02
	117,509.65
Less: Salvage	13,648.12
Net loss due to retirement	$103,861.53

Salvage is calculated as follows:

Total value of material removed by contractor	$101,040.35
Less: Material returned by contractor	66,602.74
Salvage value of material reused by contractor	34,437.61
Plus: Salvage value of material returned by contractor	7,650.78
Total salvage value of all material removed	42,088.39
Less: Salvage value of special equipment items reused by contractor	28,440.27
Salvage value of all material removed other than special equipment items	$ 13,648.12

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Total salvage value (Column 17 of the RUS Form 254b)	$ 16,364.34
Less: The salvage value of special equipment items	8,713.56
Salvage value	$ 7,650.78

Note: Special equipment items salvaged are reported in the shaded areas of the RUS Form 254b.

8.12 Journal entry discussed in Section 4.10:

Dr. 108.8, Retirement Work in Progress	$ 28,440.27	
Cr. 107.1, Construction Work in Progress - Contract		$ 28,440.27

To record the cost of special equipment items removed from service and reused by the contractor. Special equipment reused is calculated in the Schedule of Special Equipment Reused (Exhibit E). The unit prices used to calculate the value of special equipment reused are taken from Table D "Value of Material Items Creditable to Bidder" (Exhibit F).

Note: The case study is based upon the assumption that all special equipment units removed and not returned were reused by the contractor. If the borrower furnished additional units, those not required for construction were returned to the borrower unused.

8.13 Journal entry discussed in Section 4.11:

Dr. 106, Completed Construction not Classified - Electric	378,325.99	
Cr. 107.1, Construction Work in Progress - Contract		378,325.99

To record completion of the construction and energization of the line.

8.14 Journal entry discussed in Sections 4.12 and 5.4.1:

Dr. 108.8, Retirement Work in Progress	68,948.63	
Cr. 364, Poles, Towers and Fixtures		23,270.02
Cr. 365, Overhead Conductors and Devices		39,234.82
Cr. 368, Line Transformers		3,593.28
Cr. 369, Services		1,003.47
Cr. 371, Installations on Customers' Premises		1,847.04

To record the original cost of the property retired under the contract. The assembly units removed were converted into record units and summarized on the Retirement Work Order (Exhibit G). Each unit is priced at its continuing property record value to determine the original cost of the property retired.

Note: Special equipment items installed and removed are reported in the shaded areas of the RUS Form 254a.

8.9 Journal entry discussed in Section 4.7:

Dr. 107.1, Construction Work in Progress - Contract	36,720.88	
Cr. 131.1, Cash - General		36,720.88

To charge the borrower's labor and overhead. This consists of direct and indirect labor; administrative and general expenses; engineering; social security taxes; property loss, property damage, and workmen's compensation insurance; stores expense; transportation expense; employee pensions and benefits; and employee holidays and vacations.

8.10 Journal entry discussed in Section 4.8:

Dr. 154, Plant Materials and Operating Supplies	$ 10,278.75	
Cr. 143, Other Accounts Receivable		$ 10,278.75

To credit the contractor for material that was not used and was returned to stock.

8.11 Journal entries discussed in Section 4.9:

Dr. 143, Other Accounts Receivable	101,040.35	
Cr. 108.8, Retirement Work in Progress		101,040.35

To charge the contractor for the material removed from existing assembly units. The value of the material removed from existing assembly units is calculated in Column 9 of the RUS Form 254a.

Dr. 108.8, Retirement Work in Progress	66,602.74	
Cr. 143, Other Accounts Receivable		66,602.74

To credit the contractor for the material returned to the borrower. The value of the material returned to the borrower is calculated in Column 14 of the RUS Form 254b.

Dr. 154, Plant Materials and Operating Supplies	7,650.78	
Cr. 108.8, Retirement Work in Progress		7,650.78

To record the salvage value of material returned to inventory. The total salvage value of material returned to the borrower is calculated in Column 17 of the RUS Form 254a. The salvage value of the special equipment items returned must be deducted from the total to determine the value of the material returned to inventory. In the case study, the salvage value is calculated as follows:

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8.7 Journal entries discussed in Section 4.5:

Dr. 143, Other Accounts Receivable	12,179.26	
Cr. 107.1, Construction Work in Progress - Contract		12,179.26

To record special equipment items furnished by the borrower to the contractor. The cost of borrower furnished material is calculated in Column 22 of the RUS Form 254c. In the case study, the costs of special equipment items are reported in the shaded areas of the RUS Form 254c.

Dr. 583, Overhead Line Expenses	22,673.68	
Cr. 107.1, Construction Work in Progress - Contract		22,673.68

To record the labor cost incurred in removing and installing special equipment items. The cost of removing special equipment items is calculated in Column 7 of the RUS Form 254a. The cost of installing special equipment items is calculated by multiplying the labor unit price (Column 3 of the RUS Form 254a) by the quantity of units installed (Column 1 of the RUS Form 254a) and adding the products. In the case study, the cost of installing and removing special equipment items is calculated as follows:

Total cost of installing special equipment items	$ 14,852 49
Plus: Total cost of removing special equipment items	7,821.19
Total cost of installing and removing special equipment items	$ 22,673.68

Note: Special equipment items installed and removed are reported in the shaded areas of the RUS Form 254a.

8.8 Journal entry discussed in Sections 4.6 and 5.4.2:

Dr. 108.8, Retirement Work in Progress	$ 48,561.02	
Cr. 107.1, Construction Work in Progress - Contract		$ 48,561.02

To reclassify labor costs incurred in removing plant from the system under the terms of the contract. The cost of removal is calculated by deducting the cost incurred in removing the special equipment items from the total cost of removal reported in Column 7 of the RUS Form 254a. In the case study, the cost of removal is calculated as follows:

Total Cost to remove "I" units (Column 7 of the RUS Form 254a)	$ 56,382.21
Less: The cost to remove special equipment items	7,821.19
Cost of removal	$ 48,561.02

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The cash payment is calculated by deducting borrower furnished material and 10% of the remaining invoice amount. In the case study, the cash payment is calculated as follows:

Total contractor's invoice	$448,184.96
Less: Borrower furnished material	166,308.58
Cash required to satisfy contractor's invoice	$281,876.38

Total contractor's invoice	$448,184.96
Less: Amount retained (10% of the cash required to satisfy the contractor's invoice in full)	28,187.63
Cash payment	$419,997.33

Dr. 232.1, Accounts Payable - General	$ 28,187.63	
or		
Dr. 232.2, Accounts Payable - RUS Construction	28,187.63	
Cr. 131.1, Cash - General		$ 28,187.63

To record payment to the contractor of the amount retained. Final payment was made after completion of the contract and the approval of the Certificate of Completion - Contract Construction, RUS Form 187, by the borrower and the Administrator of RUS.

8.6 Journal entries discussed in Section 4.4:

Dr. 107.1, Construction Work in Progress - Contract	5,274.38	
Cr. 143, Other Accounts Receivable		5,274.38

To adjust for the difference in the price of the material furnished to the contractor at average cost and the unit prices shown in the contract (the unit prices stated in the contract were lower than the average cost). The difference between the borrower's average cost and the contract price is calculated in Column 25 of the RUS Form 254c.

Note: If the unit prices stated in the contract had been higher than the average cost, Account 143 would have been debited and Account 107.1, credited.

8.2.4 Material charged out to the contractor on Material Charge Tickets totalled $135,244.84; and

8.2.5 Material returned by the contractor unused totalled $10,278.75.

8.3 Journal entry discussed in Section 4.1:

Dr. 143, Other Accounts Receivable	$135,244.84	
Cr. 154, Plant Materials and Operating Supplies		$135,244.84

To record material taken from stock at average cost and furnished by the borrower to the contractor.

8.4 Journal entry discussed in Section 4.2:

Dr. 107.1, Construction Work in Progress - Contract	448,184.96	
Cr. 232.1, Accounts Payable - General		448,184.96
or		
Cr. 232.2, Accounts Payable - RUS Construction		448,184.96

To record the contractor's monthly invoice.

8.5 Journal entry discussed in Section 4.3:

Dr. 232.1, Accounts Payable - General	419,997.33	
or		
Dr. 232.2, Accounts Payable - RUS Construction	419,997.33	
Cr. 143, Other Accounts Receivable		166,308.58
Cr. 131.1, Cash - General		253,688.75

To record payment of the contractor's monthly invoice net of the retained amount and the charge to the contractor for material furnished by the borrower and installed by the contractor during the month. In the case study, the borrower furnished material is calculated as follows:

Materials furnished to the contractor	$135,244.84
Material adjustment	(5,274.38)
Special equipment furnished to the contractor	12,179.26
Material unused and returned	(10,278.75)
Material removed from existing assembly units	101,040.35
Material removed and returned	(66,602.74)
Borrower furnished materials	$166,308 58

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7. COMPLIANCE WITH 7 CFR Part 1721, POST-LOAN POLICIES AND PROCEDURES FOR INSURED ELECTRIC LOANS: 7 CFR Part 1721, Post-Loan Policies and Procedures for Insured Electric Loans, allows borrowers to request loan fund advances in an amount representing actual costs incurred but not to exceed 130 percent of the estimated project costs reported on the approved RUS Form 740c, Costs Estimates and Loan Budget for Electric Borrowers.

7.1 If several projects are constructed under one contract, compliance with the 130 percent requirement is determined by comparing the total actual costs incurred for all projects constructed under the contract with the total estimated costs of those projects as reported on the RUS Form 740c. The total estimated costs for all projects is used regardless of whether the different projects are included on a single work order or are assigned to separate work orders.

7.2 Contract costs are allocated to each project on a reasonable basis.

8. CASE STUDY - ACCOUNTING FOR CONTRACT CONSTRUCTION COSTS UNDER A FORM 830 CONTRACT:

8.1 The following case study illustrates the accounting for contract construction costs discussed in this bulletin. The case study includes.

8.1.1 The journal entries required to record the transactions associated with contract construction;

8.1.2 The general ledger account summaries of the principle accounts involved;

8.1.3 Completed examples of the RUS Forms 254, 254a, 254b, and 254c; and

8.1.4 All additional materials necessary to complete the case study.

8.2 For purposes of this case study, assume the following:

8.2.1 The contractor's invoice for all construction and retirement activities totalled $448,184.96. A borrower typically receives several monthly invoices before the completion of the contract and the rendering of the final bill. However, to simplify the case study, we have included all of the monthly billings in one total;

8.2.2 The borrower retained 10% of the cash payments to the contractor pending completion of the contract;

8.2.3 The borrower's labor and overhead associated with the contract totalled $36,720.88;

reused by the contractor are charged to expense. However, special equipment items furnished and installed by the contractor are capitalized. These items, shown as memorandum items on the conversion sheets, are brought forward and tabulated in the proper accounts. The total of all the record units, including the special equipment, are posted to Column 2 of the Unitization and Distribution to Plant Accounts (Exhibit V of RUS Bulletin 1767B-2).

6.5 **Standard Record Unit Costs**. Section 9.2.4 of RUS Bulletin 1767B-2 describes standard record unit costs and suggests two methods for establishing them. When the contract is for a type of construction with which the borrower has had no prior experience, such as a first contract for underground or transmission plant, information obtained from the contractor, the consulting engineer, or a similar utility may be helpful.

6.6 **Unitization and Distribution to Plant Accounts**. The Unitization and Distribution to Plant Accounts (Exhibit H) is used to distribute overhead and the other costs recorded in Account 107.1 to the appropriate record units and plant accounts. The description of the record unit is entered in Column 1 if it is not preprinted.

6.6.1 The totals from the tabulation sheets are posted to Column 2. These represent the record units converted from the new and conversion assembly units in Item A of the RUS Form 254 and include the "Special Equipment" furnished by the contractor.

6.6.2 The standard record unit costs and the total unit price of the assembly units containing special equipment, (See Section 6.1 concerning conventional transformers) from Column 5 of the RUS Form 254a, are entered in Column 3 and multiplied by Column 2 to determine the total standard costs.

6.6.3 The total amount of the contract remaining in Account 107.1 is entered in Column 5 opposite "B", Total Actual Cost, and divided by the total of Column 4, to calculate the ratio of actual to standard costs.

6.6.4 The standard cost of the individual record units in Column 4 is multiplied by this ratio to determine the total actual cost for Column 5.

6.6.5 The units and costs in Columns 2 and 5 are posted to the continuing property records.

6.6.6 Column 5 is summarized by plant account and a journal entry is made charging the classified plant accounts and crediting Account 106.

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6. UNITIZATION AND CLASSIFICATION BY RECORD UNITS AND PRIMARY PLANT ACCOUNTS:

6.1 **The assembly unit for a conventional transformer** also contains a lightning arrester and a cutout which are record units. These units are included in the Tabulation of Record Units and included on the Unitization and Distribution to Plant Accounts (See Section 6.6).

6.2 **The "H" Conversion Assembly Units** included in Column 2 of the RUS Form 254a have no counterpart in the work order procedure. They are described in Section H of the RUS Form 830. The cost of these units includes the labor and any additional material required to change an existing pole-top assembly unit to a different unit.

6.2.1 Conversion assembly units are identified by the prefix "H" with the new construction assembly unit shown first followed by the existing assembly unit. For example H B1:A1 requires the addition of a crossarm, crossarm pins, braces, machine bolt, carriage bolts, lag screw, and insulator; the existing insulator, sing upset bolt, and neutral spool is used in the new unit and the tractor retains the pole top pin and two machine bolts. Appendix I of RUS Bulletin 1767B-2, indicates that an A1 construction assembly unit contains no retirement units while a B1 assembly unit includes the addition of a crossarm retirement unit.

6.2.2 These units, suitably grouped into record units are summarized on the Tabulation of Record Units and included on the Unitization and Distribution to Plant Accounts (See Section 6.6).

6.3 **The conversion of standard new assembly units to record units** is similar to the conversion of construction costs outlined in Section 9, Unitization and Classification of Work Order Costs by Record Units and Primary Plant Accounts, of RUS Bulletin 1767B-2. Appendix I of the RUS Bulletin 1767B-2 contains tables that convert construction units to retirement units. RUS Bulletin 181-2, Standard List of Retirement Units, defines a construction unit, retirement unit and record unit. RUS Bulletin 184-3, Guide for Establishing Continuing Property Records, discusses the organization of record units. Exhibits Q and R, Conversion to Record Units of Property, of RUS Bulletin 1767B-2 may be useful in the conversion. They provide for the direct conversion from construction units to record units without the intermediate retirement units.

6.4 **Tabulation of Record Units**. Exhibit S, Tabulation of Record Units - Overhead, and Exhibit T, Tabulation of Record Units for Underground Staking Sheets, of RUS Bulletin 1767B-2 may be useful in summarizing construction by record units. The cost of labor and minor items of property associated with special equipment items furnished to the contractor by the borrower or removed and

4.11 **When the contract is complete** and the completed construction is placed in service, the costs remaining in Account 107.1 are closed to Account 106, Completed Construction not Classified - Electric. After completion of the Unitization and Distribution of Costs, the appropriate plant accounts are charged.

4.12 **The original cost of all plant retired** from service must be eliminated from the appropriate plant accounts and charged to Account 108.8. (See Section 5.)

5. RETIREMENTS:

5.1 **The Section I - Removal Assembly Units**, shown in Column 2 of the RUS Form 254a, are converted to retirement units using the conversion tables in Appendix I of RUS Bulletin 1767B-2. The retirement units are grouped into suitable record units, as shown in Appendix I to RUS Bulletin 1767B-2.

5.2 The engineer should provide the borrower with the number of grounds removed by the contractor. This enables the grounds to be included in the tabulation of retirement units and their value to be included in the original cost of plant retired.

5.3 The engineer should provide the borrower with the number of anchor-guy assemblies removed if it differs from the inventory tabulation in the contract.

5.4 The record units are then summarized (Exhibit S, Tabulation of Record Units - Overhead, and Exhibit T, Tabulation of Record Units for Underground Staking Sheets, of RUS Bulletin 1767B-2 may be used) and priced at the unit costs obtained from the continuing property records to derive the original cost of property retired.

5.4.1 The original cost of property retired is charged to Account 108.8 and credited to the plant accounts.

5.4.2 The cost of removal is charged to Account 108.8 and credited to Account 107.1.

5.4.3 The total amount of the material returned to stock and the amount reused by the contractor is considered salvage.

5.4.4 The "Net Loss Due to Retirement" (the original cost of property retired plus the cost of removal less salvage) is charged to the appropriate accumulated provision for depreciation and credited to Account 108.8.

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4.8 **Material furnished to the contractor that is not used** and is returned to the borrower is returned to inventory by debiting Account 154. By returnin the material, the contractor is no longer held accountable; refore, Account 143 is credited. Material Credit Tickets ibit C of RUS Bulletin 1767B-2) should be prepared for a material returned by the contractor.

4.9 **Material removed from existing facilities** is charged to t contractor by debiting Account 143 and crediting Account 108.8. If the contractor returns the material to the borrower, the contractor is relieved of his responsibility for the material by crediting Account 143 and ebiting Account 108.8. If the mat rial is returned to t borrower, Material Salvage Tickets (Exhibit E of RUS Bulleti 767B-2) are prepared.

4.9.1 The Material Salvage Tickets are included in the Summary of Material Salvage Ti ets (Exhibit F of RUS Bulletin 1767B-2) for the month and are entered in the Materials Register (Exhibit G of RUS Bulletin 1767B-2) as a debit to Account 154 and a credit to Account 108.8. If the material is reusable, it is priced as follows:

4.9.1.1 Large, individual ems are priced at their original cost, estimated if not know The cost of repairing these items is charged to the maintenan account appropriate for the previous use; or

4.9.1.2 Relatively small items, the identity of which cannot be ascertained without undue refinement in accounting, are priced at current prices new for such items. The cost of repairing these items is charged to the maintenance account appropriate for the previous use.

4.9.2 Salvage tickets should be signed by both the borrower and the contractor or their agents with a copy furnished to the contractor.

4.9.3 The RUS rm 254b pr des space, in Columns 15, 16 and 17, for track reusable it ns salvaged although the amount payable to the contractor is not affected.

4.10 **The cost of special equipment items removed from service and reused** by the contractor have already been charged to retirement (See Section 4.9) and to construction when the contractor's invoice is recorded (See Section 4.2). Since these items are no longer retired, they must be debited to Account 108.8. As discussed in Section 4.5, special equipment items are capitalized upon purchase and any duplicate capitalization of their costs must be eliminated. When the contractor's invoices are recorded, special equipment that has been sed is included in the invoice, as well, and is, ther e, capit ized to Ac nt 107.1. Account 107.1 must be credi d to avo the duplic capitalization.

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4.4.1 If the unit price stated in the contract is higher than the average cost of the material recorded in Account 143, Account 107.1 must be credited to reflect the lower cost.

4.4.2 If the unit price stated in the contract is lower than the average cost of the material recorded in Account 143, Account 107.1 must be debited to reflect the higher cost.

4.5 Special equipment items are capitalized to the appropriate plant account upon purchase. Therefore, for purposes of tracking special equipment items furnished to the contractor, they are charged to Account 143 at the unit prices shown in the List of Borrower's Materials on Hand in the RUS Form 830. Their cost is charged to construction when the monthly contractor invoices are recorded. When the invoices are recorded, special equipment costs have been capitalized twice - once upon purchase to the appropriate plant account and a second time to construction. The offsetting entry to Account 143 is, therefore, a credit to Account 107.1. This eliminates the duplicate capitalization and retains the original cost of the special equipment items in the proper plant accounts.

4.5.1 The contractor's labor costs for installing and removing special equipment items are deducted from the costs charged to construction by crediting Account 107.1 and charging the appropriate expense account as follows:

4.5.1.1 Account 583, Overhead Line Expenses, or Account 584, Underground Line Expenses, for transformers, oil circuit reclosers, voltage regulators and sectionalizers; or

4.5.1.2 Account 586, Meter Expenses, for meters, meter sockets, current and potential transformers and other metering equipment.

4.6 The labor costs incurred in removing items from plant must be reclassified from construction to retirement by charging Account 108.8, Retirement Work in Progress, and crediting Account 107.1 Because the cost of the contractor's invoice initially charged to construction included both construction and retirement costs (See Section 4.2), the amount applicable to retirement must be reclassified to retirement work-in-progress.

4.7 Other direct and indirect construction costs incurred by the borrower that are required to complete the contract are detailed and defined in Part 1767, Section 1767.16 (c), Components of Construction Cost. These non-contract costs are charged to Account 107.1.

4.7.1 These costs should be accumulated on a separate work order; however, they should be submitted to RUS for financing on the same RUS Form 219, Inventory of Work Orders (Exhibit I), that includes the associated contract.

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records a receivable from the contractor. Material is charged to the contractor using Account 143, Other Accounts Receivable, and is credited to Account 154, Plant Materials and Operating Supplies, at its average cost. No material cost is charged to construction at this time. The monthly invoices submitted by the contractor include the cost of borrower furnished material and material provided by the contractor and the contractor's labor costs. Therefore, borrower furnished material is charged to construction when the monthly contractor invoices are recorded. (See Section 4.2.)

4.1.1 The RUS Form 830 contains a sample materials receipt form for material furnished to the contractor at contract price. The receipt should be signed by both the contractor and the borrower or their agents.

4.2 <u>The total cost reported on the monthly invoices</u> (material and labor) that are certified to and submitted by the contractor, recommended by the borrower's engineer, and approved by the borrower is charged to Account 107.1, Construction Work in Progress - Contract. Either Account 232.1, Accounts Payable - General, or Account 232.2, Accounts Payable - RUS Construction, is credited, as appropriate.

4.3 <u>Payments to the contractor</u> (the invoice amount less the amount retained) are debited to the appropriate subaccount of Account 232. A portion of each invoice is retained pending completion of the contract and the approval of the Certificate of Completion - Contract Construction, RUS Form 187, by the borrower and the Administrator of RUS.

4.3.1 The amount of borrower furnished material included in the invoice is credited to Account 143 at the unit prices shown in the List of Borrower's Materials on Hand in the RUS Form 830. Because the contractor has installed the portion of the borrower furnished material in the units included in the invoice, the contractor is no longer accountable for that portion of the material. Account 143 is credited to relieve the contractor of that responsibility.

4.3.2 As provided for in Article I, Section 3, of the RUS Form 830, the monthly invoice payable to the contractor is reduced by the cost of material furnished by the borrower and installed by the contractor during the month. The difference between the amount of the invoice, the amount retained, and the credit for owner furnished material (Account 143) is credited to Account 131.1, Cash - General.

4.4 <u>Because borrower furnished material is charged to construction at contract prices</u> rather than actual costs, it is necessary to adjust Account 107.1 to reflect the actual cost of the material.

3.2 Item B, "Cost to Remove "I" Units," on the RUS Form 254 includes the labor costs incurred in removing "I" units in accordance with the contract. Removal costs are tabulated in Column 7, Due Contractor for Units Installed, Converted and Removed - Cost to Remove "I" Units, of the RUS Form 254a and the total is reported as Item B.

3.3 The cost of installing special equipment items furnished by the borrower and the cost of reinstalling special equipment items previously removed are included in Item A. The cost to remove special equipment is included in Item B. These amounts should be charged to expense when the monthly invoices are recorded. (See Section 10.1 of RUS Bulletin 1767B-2, Work Order Procedure (Electric), for a definition of special equipment items.)

3.4 Item C, "Amount to be Credited to Contractor for Materials Removed from Existing Facilities and Returned," includes the cost of material, at contract prices, removed from service and returned to the borrower. This amount is tabulated in Column 14, Total Credit to Contractor, of the RUS Form 254b and the total is reported as Item C. The RUS Form 254b is used only when the contract contains "I" removal units (See Section I of the RUS Form 830).

3.5 Item D, "Amount Chargeable to Contractor for Materials in Assembly Units Removed," includes the cost of material, at contract prices, removed from service and retained by the contractor. This amount is tabulated in Column 9, Amount Chargeable to Contractor for Materials in Assemblies Removed - Total, of the RUS Form 254a and the total is reported as Item D Each line item in Column 9 is calculated by multiplying the number of units removed by the unit material values from Table C of the RUS Form 830.

3.6 Item E, "Net Amount of Owner-Furnished Materials," includes material furnished by the borrower. This amount is tabulated in Columns 20 through 24 of the RUS Form 254c and the total of Column 24 is reported as Item E.

3.7 Item F, "Net Amount Due Contractor," is the net amount of items A through E. When making the final payment to the contractor, this amount is reduced by all prior payments made on the contract to date and any amounts, such as liquidated damages, due the borrower.

4. **ACCOUNTING FOR CONTRACT CONSTRUCTION COSTS.** When the terms of the contract are met over an extended period of time, all or a part of the contract amount is recorded prior to the preparation of the RUS Form 254.

4.1 <u>Borrower furnished material</u> is charged out of inventory to the contractor using Material Charge Tickets. The contractor now becomes accountable for this material and, as such, the borrower

1. **GENERAL:** The function of plant accounting is to record the various elements of construction and retirement costs in a manner that satisfies the requirements of 7 CFR Part 1767, Accounting Requirements for Rural Utilities Service (RUS) Electric Borrowers, Subpart B, Uniform System of Accounts (Part 1767), and to form the basis for recording plant additions and retirements.

1.1 **The objective** of this bulletin is to provide guidance on the preparation and use of the RUS Form 254, Construction Inventory, and the RUS Form 830, Electric System Construction Contract. The Form 830 contract is illustrated in this bulletin because it utilizes the RUS Forms 254a, 254b, and 254c, in their entirety. The RUS Form 254 is, however, also used to close out the cost of completed construction for the following contracts:

1.1.1 Transmission System Right of Way Clearing Contract, RUS Form 203;

1.1.2 Substation and Switching Station Erection Contract, RUS Form 764;

1.1.3 Electric Transmission Construction Contract, RUS Form 831.

2. **ENGINEERING:** The borrower's engineer monitors construction progress and recommends the amount of the contractor's monthly invoice to be paid in accordance with Article III, Section 1, of the RUS Form 830.

2.1 When construction is completed, as defined in the RUS Form 830, the engineer prepares five copies of the RUS Forms 254, Construction Inventory (Exhibit A) and 254a (Exhibit B). If applicable, the engineer also prepares five copies of the RUS Forms 254b (Exhibit C) and 254c (Exhibit D).

2.2 The engineer also performs the duties set forth in RUS Bulletin 81-6, Closeout Procedures and Documents for Contract Construction of Distribution and Transmission Facilities.

3. **CONSTRUCTION INVENTORIES:** The total amount to which the contractor is entitled is calculated on the RUS Form 254.

3.1 Item A, "Total Cost of Standard, New and Conversion Assembly Units Installed," of the RUS Form 254 includes the labor and material costs of the units installed. These costs are calculated in Column 1 and Columns 3 through 6 of the RUS Form 254a. The total of Column 6, Cost of Construction, is the total cost reported as Item A.

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TEXT:

1. General
2. Engineering
3. Construction Inventories
4. Accounting for Contract Construction Costs
5. Retirements
6. Unitization and Classification by Record Units and Primary Plant Accounts
7. Compliance with 7 CFR Part 1721, Post-Loan Policies and Procedures for Insured Electric Loans
8. Case Study - Accounting for Contract Construction Costs

EXHIBITS TO TEXT:

A: RUS Form 254, Construction Inventory
B: RUS Form 254a, Construction Inventory
C: RUS Form 254b, Construction Inventory
D: RUS Form 254c, Construction Inventory
E: Schedule of Special Equipment Reused
F: Table D - Value of Material Items Creditable to Bidder
G: Retirement Work Order
H: Unitization and Distribution to Plant Accounts
I: RUS Form 219, Inventory of Work Orders

INDEX:

Accounting
Contract Procedures
RUS Form 254, Construction Inventory

ABBREVIATIONS

RUS Rural Utilities Service

INSTRUCTIONS

The Engineer will prepare 5 copies of RUS Form 254 and 254a also 5 copies of Forms 254b and 254c when applicable Original and 1 copy to be forwarded to RUS 1 copy to Contractor 1 copy to Owner and 1 copy to be retained by Engineer

Calculation of amount payable to Contractor will employ data taken from columns 1 through 25, RUS Forms 254, 254a 254b 254c The amounts to be inserted opposite Items A, B C D and E on RUS Form 254 are indicated in the texts of those items.

Columns 1 through 17 Forms 254a and *(Form 254b is required only when "I" removal units are included in the Contract)*

COLUMN	SOURCE OF INFORMATION
1 and 2	From tabulation of staking sheets *
3 and 4	From Contract.
5	Column 3 plus column 4
6	Column 1 multiplied by column 5
7	Column 1 multiplied by column 3 *(for "I" units only)*
8	From Table C of Contract.
9	Column 1 multiplied by column 8 for "I" removal units only *(Table C relates solely to "I" units.)*
10 11 and 12	From Engineer's and Owner's records
13	From Table D in Contract.
14	Column 12 multiplied by column 13
15	From Engineer's records *(Quantities shall be listed opposite the appropriate material items described in column 11)*
16	From individual stock record card for for each material item listed
17	Column 15 multiplied by column 16

Data shown on Form 254c to be presented under the following headings as appropriate

PART I MATERIAL ITEMS INCLUDED IN LISTS SET FORTH IN CONSTRUCTION CONTRACT

PART II OTHER MATERIAL ITEMS FURNISHED BY OWNER

Columns 18 through 25 *(Form 254c is required only when threre are owner–furnished materials)*

COLUMN	SOURCE OF INFORMATION
18 and 19	From Contract and Material Receipts
20	From charge–out and credit tickets covering materials issued to and returned by the Contractor **
21	From average unit costs on charge–out and credit tickets relating to this construction such costs in turn being taken from the average unit costs reflected by the stock record cards for the applicable period
22	Column 20 multiplied by column 21
23	For Part I from the unit prices specified in the Contract in the "List of Owner's Materials on Hand" or the "List of Materials Ordered by Owner But Not Delivered " For Part II from the actual unit costs to Owner – the same as used in column 21
24	Column 20 multiplied by column 23
25	Column 24 minus column 22 *(If a minus quantity enter in parentheses)*

The completed Construction Inventory, together with all other final papers as set forth in RUS Bulletins relating to the close–out of contracts is to be submitted to RUS for approval of the amount due the Contractor

Upon approval of the inventory by RUS one copy each of approved Forms 254 254a 254b and 254c will be returned to the Owner by RUS

Reference should be made to RUS Bulletin 1767B–2 Contract Accounting Procedure, for instruction in accounting for all contract costs including the retirement of units removed by the Contractor and the unitization by record units of costs of construction assemblies installed by the Contractor

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* *Standard units will be listed first, followed by new units and conversion units, in that order with all "I" removal units being listed last.*

** *The quantities shown in column 20 should agree with Material Receipts (RUS Form 251) prepared in connection with the contract. The types of items of material and the quantity of any item of material listed under Part I of the tabulation should be limited to the type of items and should not exceed the quantity of any item of material specified in the construction contract in the "List of Owner's Materials on Hand" or the "List of Materials Ordered by Owner But Not Delivered." Any additional items of material or excess quantities over the items specified in such lists are to be shown under Part II of the tabulation.*

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254.

SHEET OF SHEETS

DATE: April 11, 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: REO Construction Company

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED, CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT T UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.5)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.5)
1	2	3	4	5	6	7	8	9
3	N30–6	87 14	50.06	137.20	411.60			
6	N35–4	102.36	88 01	190.37	1,142.22			
20	N35–5	102.36	74.80	177 16	3,543.20			
4	N35–6	102.36	65.25	167 61	670 44			
3	N40–3	116.19	125 14	241.33	723 99			
111	N40–4	116.19	117.22	233 41	25,908.51			
11	N40–5	116.19	94.84	211 03	2,321.33			
2	N40–6	116.19	86 72	202.91	405 82			
8	N45–3	131.40	160 03	291 43	2,331.44			
42	N45–4	131.40	128.09	259 49	10,898.58			
23	N50–3	177 05	170.08	347 13	7,983 99			
21	N50–4	177.05	152.55	329 60	6,921.60			
4	N55–3	224 08	234 45	458.53	1,834 12			
1	NA3	33.20	41.31	74.51	74.51			
1	NB8	150.00	135 00	285.00	285 00			
254 634	ND#1/O ACSR.6/1	121.68	114.52	236.20	60,144.55			
76 608	ND#2 ACSR.6/1	114 40	84 87	199.27	15,265 68			
54.516	ND#336 ACSR.18/1	312.00	352.37	664.37	36,218.79			
8 139	ND#4 ACSR.7/1	106.08	64 71	170 79	1,390 06			
4.228	ND#6 HDCU	93 60	40 89	134 49	568.62			
273	NE1–2	30 43	22.58	53 01	14 471.73			
54	NE1–3	38 73	32.82	71.55	3,863 70			
14	NE2–2	52.56	25 15	77 71	1,087 94			
9	NE2–3	60.86	33 02	93.88	844.92			
17	NE3–10	13.83	5.25	19.08	324.36			
163	NF1–2	37.35	10.25	47 60	7,758.80			
37	NF1–3	37.35	13 48	50.83	1,880 71			
3	NG10–CONV	87.14	264.56	351.70	1,055.10			
32	NG10–CSP	87 14	264.56	351.70	11,254.40			
3	NG15–CONV	99.59	316.83	416.42	1,249.26			
22	NG15–CSP	99.59	322.38	421.97	9,283.34			
1	NG15–CSPR	100.00	0.00	100 00	100.00			
1	NG210–10.25	472.50	911.21	1,383 71	1,383.71			

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254.

SHEET OF SHEETS

DATE: April 11 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: REO Construction Company

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT T UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.5)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
1	NG210–15.50	605.16	961.21	1,566.37	1,566.37			
1	NG210–25.25	472.50	931.21	1,403.71	1,403.71			
1	NG25–CONV	117.57	498.95	616.52	616.52			
7	NG25–CSP	117.57	349 04	466.61	3,266.27			
2	NG25–CSPR	100.00	0.00	100.00	200 00			
1	NG310–15 15.15	611.93	1,310.36	1,922.29	1,922.29			
2	NG37–CSP	152.95	421.61	574.56	1,149 12			
1	NG37–CSPR	100.00	0.00	100.00	100.00			
7	NG5–CSP	87.14	177.29	264 43	1,851.01			
1	NG7–CSP	87 14	220 05	307 19	307.19			
1	NGV10–CONV	87.14	590.21	677.35	677.35			
18	NGV10–CSP	93.10	499 62	592.72	10 668.96			
8	NGV15–CSP	103 74	617.32	721.06	5,768 48			
2	NGV25–CSP	123 69	712.34	836.03	1,672.06			
2	NJ10	8.30	5 19	13 49	26.98			
11	NJ5	6.92	3 74	10 66	117.26			
27	NJ6	11 07	9.30	20.37	549 99			
1	NJ8	8.30	3.29	11.59	11.59			
0 680	NK#1/0 TPX	600.31	386 63	986.94	671 12			
4 804	NK#2 TPX	549 13	299 15	848.28	4,075 14			
0 150	NK#4 TPX	521 47	250 00	771.47	115 72			
0.214	NK#8 WPCU	124 49	31 16	155 65	33.31			
7	NK10	6.92	3.24	10.16	71.12			
4	NK10C	6 92	5.84	12.76	51 04			
163	NK11	8.30	6.43	14 73	2,400 99			
10	NK14	9 68	4 41	14.09	140 90			
131	NM2–11	20 75	15 86	36 61	4 795 91			
120	NM2–12	17 98	12.03	30 01	3 601.20			
7	NM2–2	17 98	13 64	31.62	221.34			
7	NM26–5	41.50	39 17	80 67	564 69			
46	NM2A	9 98	2.21	12.19	560 74			
9	NM2B	22.28	2.21	24 49	220 41			
2	NM3–10	112.04	272.55	384.59	769.18			

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET OF SHEETS

DATE: April 11 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: REO Construction Company

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED, CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT T UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.3)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
1	NM3–12A	497.96	2,372.63	2,870.59	2,870.59			
1	NM3–25A	746.93	2,372.63	3 119.56	3,119.56			
1	NM3–4	37 91	77 98	115 89	115 89			
6	NM42–11	20 00	10.50	30.50	183 00			
2	NM5–1	6.92	7.04	13.96	27 92			
2	NM5–10	45 65	82.32	127 97	255 94			
4	NM5–14	16 60	13 75	30.35	121.40			
6	NM5–17	6.92	3.24	10 16	60 96			
7	NM5–23	15 00	23 00	38 00	266 00			
12	NM5–27	22.28	16 80	39 08	468.96			
11	NM5–6	29 05	31 92	60 97	670 67			
41	NM5–9	34.58	57 12	91 70	3 759 70			
1	NM8–10	60 00	0 00	60 00	60 00			
2	NM8–12	60 00	0 00	60 00	120 00			
1	NM8–9	39 90	228.17	268.07	268.07			
1	NM7–11	719.26	1,393.20	2,112.46	2,112.46			
8	NVA1	15.22	20 01	35.23	281.84			
3	MVA2	30 43	36.25	66 68	200 04			
1	MVA3	33.20	41.31	74.51	74.51			
1	NVA4	69 16	78 62	147 78	147 78			
5	NVA5	31 81	37.21	69 02	345 10			
2	NVA5–1	45 65	41 41	87 06	174 12			
77	NVA5–2	48 41	48 77	97 18	7 482.86			
2	NVA6	77 46	72.63	150 09	300 18			
3	NVB1	41.50	55 13	96 63	289 89			
1	NVB3	50 00	103 00	153.00	153 00			
3	NVB5–1	55.33	72.84	128 17	384.51			
1	NVB7	78 84	127 18	206.02	206 02			
2	NVB7–1	71 93	127 18	199 11	398.22			
86	NVC1	45 65	70 72	116.37	10,007 82			
3	NVC1–1	84.38	144.22	228.60	685 80			
26	NVC1–2	55.33	89 71	145 04	3,771 04			
19	NVC1–3	69 16	195 03	264 19	5,019 61			

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET	OF SHEETS
DATE: April 11, 19X4	PROJECT DESIGNATION: State 99 County
BORROWER: County Electric Cooperative	
ENGINEER: Big Engineering Company	
CONTRACTOR: REO Construction Company	

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED, CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT T UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.3)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
2	NVC1P2	63.84	186.19	250 03	500 06			
48	NVC2	91.29	148.19	239 48	11 495 04			
1	NVC2–1	91.29	210 69	301.98	301.98			
5	NVC2–2	95 44	210 69	306.13	1,530 65			
34	NVC3	63 63	120.95	184.58	6,275 72			
3	NVC3–1	69 69	267.57	337.26	1 011 78			
2	NVC3L	77 46	204.38	281.84	563 68			
2	NVC4	172.90	227 64	400.54	801.08			
12	NVC4–1	172.90	227 64	400.54	4 806 48			
3	NVC4–1L	172.90	360.80	533 70	1 601.10			
6	NVC5–1	81.33	107 96	189.29	1 135 74			
1	NVC5–1L	81 61	161.68	243.29	243.29			
1	NVC7	98.21	142.11	240.32	240.32			
3	NVC7–1	114 81	157.21	272.02	816.06			
1	NVC7–1S	114.81	157.21	272.02	272.02			
6	NVC8	210.25	264.81	475 06	2,850.36			
1	NVC9	91.29	175 89	267 18	267 18			
1	NVM2–9	9 68	2.25	11.93	11 93			
1	NVM3–12A (50E)	497 96	2,372.63	2,870.59	2,870.59			
1	NVM3–16	532.28	1,969 97	2,502.25	2,502.25			
1	NVM3–25	746.93	2,372.63	3,119.56	3,119.56			
2	NVM3–3	497 67	439 81	937 48	1 874 96			
1	NVM3–35SB	151.62	788.57	940 19	940 19			
3	NVM5–2	9 68	12.13	21 81	65 43			
43	NVM5–20	13.83	21 67	35.50	1,526.50			
26	NVM5–4	9 68	11 61	21.29	553.54			
21	NVM5–5	6.92	10 96	17 88	375 48			
21	NVM5–6	29 05	51 87	80 92	1 699.32			
25	NVM5–9	34.58	57 12	91 70	2,292.50			
30	N DEAD END CLAMP	20 00	10.50	30.50	915 00			
1	HVA5–2.A5	71 91	20 41	92.32	92.32			
5	HVA5–2.A5–2	71 91	20 41	92.32	461 60			
3	HVA5.A5	47 03	20 41	67 44	202.32			

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254.

SHEET OF SHEETS

DATE: April 11, 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: REO Construction Company

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED, CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT 'T' UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.3)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
1	HVA7.A7	86.29	20 41	106.70	106.70			
1	HVB5 B5	81 61	40 82	122.43	122.43			
1	HVB7 B7	118.26	127 18	245 44	245 44			
3	HVC1–2.C1	78.84	68 18	147.02	441.06			
2	HVC1–2.C1A	78.84	68.18	147.02	294 04			
1	HVC1–3-C2	107 89	153.20	261.09	261.09			
7	HVC1.A1	53 94	67.20	121.14	847.98			
1	HVC1.B1	65.01	44 98	109 99	109 99			
1	HVC1.C1–2	69 16	70 72	139.88	139.88			
4	HVC1.VA1	53 94	50 15	104 09	416.36			
1	HVC2.A1	99.59	148 19	247 78	247 78			
5	HVC2.A2	105 12	144 15	249.27	1,246.35			
1	HVC2.VA2	102.36	108.10	210 46	210 46			
1	HVC3 B3	88.52	80 98	169.50	169.50			
1	HVC4–1-C4–1L	246.21	122.47	368.68	368.68			
1	HVC5–1.A5–1	105 12	91.20	196.32	196.32			
1	HVC5–1:A5–2	105.12	81 65	186.77	186.77			
1	HVC5–1 C5–1	112.04	61.24	173.28	173.28			
2	HVC5–1 C5–1L	112.04	61.24	173.28	346.56			
1	[illegible]C5–1 VA5–2	105 12	63 43	168.55	168.55			
1	[illegible]C5–2.A5–2	105.54	107 96	213.50	213.50			
1	HVC7–1 B7–1	135 66	72.10	207 76	207 76			
1	HVC7–1 C7–1	168.65	61.24	229 89	229.89			
1	HVC7–1 VA5	130.55	120 10	250 65	250 65			
1	HVC7 C7	143 85	61.24	205.09	205 09			
1	HVC8.A6	244 77	233.82	478.59	478.59			
1.00	C.O #1	881.95	646.63	1,528.58	1,528.58			
1	I25' POLE	44.26				44.26	55.00	55.00
2	I30' POLE	44.26				88.52	58.68	117.36
116	I35' POLE	51 18				5,936.88	78 46	9 101.36
60	I40 POLE	58 09				3 485 40	111 65	6 699 00
8	I45' POLE	58.09				464 72	139.26	1,114 08
1	I50' POLE	88.52				88.52	150 00	150 00

U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254.

SHEET OF SHEETS

DATE: April 11 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: REO Construction Company

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT 'T' UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.3)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
53	IA1	8.30				439 90	9.32	493 96
31	IA2	13 83				428.73	15 93	493 83
7	IA3	16.60				116.20	22.65	158.55
7	IA4	30 43				213.01	40.56	283 92
13	IA5	15.22				197 86	21.54	280 02
27	IA5–1	23.51				634 77	26.82	724 14
14	IA5–2	23.51				329 14	28 62	400 68
3	IA6	34.58				103 74	28 62	85 86
18	IB1	19.36				348 48	34 10	613 80
5	IB1S	19.36				96.80	34 10	170.50
2	IB2	34.58				69 16	61 96	123 92
5	IB2C	37 24				186.20	84 96	424 80
1	IB2S	34.58				34.58	66 83	66 83
1	IB3	25 00				25.00	39 76	39 76
1	IB4	52.56				52.56	83 14	83 14
1	IB4–1	52.56				52.56	90 96	90 96
1	IB5	24 90				24.90	38 40	38 40
5	IB5–1	24 90				124.50	43 69	218 45
1	IB7–1	44.26				44.26	80 85	80 85
1	IB8	69 16				69 16	124 89	124 89
15	IC1	23.51				352.65	37 40	561 00
12	IC1A	23.51				282.12	40 98	491 76
1	IC1P	29.26				29.26	38.50	38.50
1	IC2	38 73				38 73	89 14	89 14
6	IC2A	25.27				151 62	90 68	544 08
4	IC8	102.36				409 44	171 08	684.32
2	IC9	44.26				88.52	102.71	205 42
41 918	ID#1/0 ACSR	82.99				3 478.77	107 45	4,504 09
12.001	ID#2 ACSR	82.99				995 96	92.83	1 114 05
13 798	ID#2/0 ACSR	110 66				1,526 89	135 94	1,875 70
35 011	ID#4 ACSR	82.99				2,905.56	59 63	2,087 71
0.265	ID#3 HDCU	82.99				21 99	55 62	14 74
145 438	ID#6 HDCU	82.99				12,069 90	38 94	5 663 36

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET	OF SHEETS
DATE April 11, 19X4	PROJECT DESIGNATION State 99 County
BORROWER County Electric Cooperative	
ENGINEER Big Engineering Company	
CONTRACTOR REO Construction Company	

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT 'T' UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.5)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
0.230	ID#6 CWLD	82.99				19 09	45.72	10.52
10	IE1–1	16 60				166.00	17 46	174 60
188	IE1–2	16 60				3 120 80	17 46	3,282.48
1	IE2–1	23.51				23.51	15 85	15 85
9	IE2–2	23.51				211.59	20.27	182.43
5	IE3–10	30 43				152.15	4.24	21.20
7	IE3–2	30 43				213.01	18.39	128.73
85	IF–ROD ONLY	6.65				565.25	6.70	569.50
2	IG15–CSP	49 80				99.60	88.12	176.24
1	IG10–CONV	49.80				49.80	280.03	280 03
39	IG10–CSP	49 80				1,942.20	227.33	8,865 87
1	IG15–CONV	49.80				49.80	303.29	303.29
16	IG15–CSP	66.50				1,064.00	282.40	4,518 40
1	IG210–10,25	165 98				165.98	688 08	688 08
1	IG210–15,50	227 40				227.40	1,239 44	1,239 44
1	IG210–25,25	188.98				188.98	1,044.71	1,044 71
4	IG25–CSP	82.46				329 84	307.95	1,231 80
1	IG310–15,15,15	305.97				305.97	969 01	969 01
2	IG37–CSP	93 10				186.20	376.90	753 80
10	IG5–CSP	49 80				498.00	144.22	1 442.20
2	IG7–CSP	93.10				186.20	184.94	369 88
1	IGVSO–CONV	49.80				49.80	563.65	563 65
21	IGV10–CSP	49 80				1,045 80	451.45	9,480 45
5	IGV15–CSP	66.50				332.50	563.49	2,817 45
1	IGV25–CSP	82.47				82.47	653 99	653 99
15	IJ10	6.92				103 80	3 65	54 75
13	IJ5	4 15				53 95	0.81	10.53
80	IJ6	6 92				553 60	6.20	496 00
3	IJ8	4 15				12.45	2.36	7 08
4	IJ9	6 92				27 68	8.50	34.00
0 170	IK#1/0 TPX	300 16				51.03	367 81	62.53
2.138	IK#2 TPX	276 64				591 46	246.73	527.53
3 036	IK#6 WPCU	82.99				251 96	59.36	180.22

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET	OF SHEETS
DATE April 11, 19X4	PROJECT DESIGNATION State 99 County
BORROWER County Electric Cooperative	
ENGINEER Big Engineering Company	
CONTRACTOR REO Construction Company	

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED, CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT "I" UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.3)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
1.256	IK#8 WPCU	82.99				104.24	39 75	49 93
40	IK10	2.77				110.60	1.50	60 00
1	IK10C	2.77				2.77	2.00	2.00
134	IK11	5.53				741.02	5.93	794 62
3	IK14	5.53				16.59	2.83	8.49
4	IK17	4 15				16 60	5.79	23 16
7	IM26–5	27 66				193 62	45 00	315 00
1	IM3–10 (50e)	52.56				52.56	1,279.92	1,279.92
4	IM3–10	52.56				210.24	225.94	903.76
1	IM3–24	373.47				373 47	451.88	451.88
1	IM3–4	17.29				17.29	36.37	36.37
2	IM5–1	5.53				11.06	6.49	12.98
1	IM5–10	16 60				16 60	101.98	101.98
6	IM5–14	6.92				41.52	14 17	85.02
2	IM5–17	2.77				5.54	4.56	9 12
9	IM5–2	4 15				37.35	7.00	63.00
4	IM5–20	6.92				27 68	12.66	50 64
1	IM5–27	6 92				6.92	13.50	13.50
6	IM5–4	4 15				24.90	5 81	34 86
5	IM5–5	4 15				20 75	3.50	17.50
5	IM5–6	16 60				83 00	27.29	136.45
18	IM5–9	11.07				199.26	42.00	756.00
1	IM7–13	380.38				380.38	8,250.00	8,250 00
1	IM8–10	30.00				30.00	0.00	0.00
2	IM8–12	30.00				60.00	0.00	0 00
1	IM8–9	19 95				19.95	65 44	65 44
1	IM9–13 100KVAR	359 63				359 63	1,230.64	1,230 64
29	IVA1	8.30				240 70	12.53	363.37
15	IVA2	13 83				207 45	22.85	342.75
2	IVA3	16 60				33.20	30 71	61 42
3	IVA4	30 43				91.29	61 19	183.57
9	IVA5	15.22				136 98	29 70	267.30
16	IVA5–1	23.51				376.16	31.29	500 64

U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET	OF SHEETS
DATE April 11 19X4	PROJECT DESIGNATION State 99 County
BORROWER County Electric Cooperative	
ENGINEER Big Engineering Company	
CONTRACTOR REO Construction Company	

ASSEMBLY UNITS		DUE CONTRACTOR FOR UNITS INSTALLED, CONVERTED AND REMOVED					AMOUNT CHARGEABLE TO CONTRACTOR FOR MATERIALS IN ASSEMBLIES REMOVED	
			EXCEPT T UNITS					
QUANTITY	STANDARD N – NEW H – CONVERSION I – REMOVAL	LABOR UNIT PRICE	MATERIAL UNIT PRICE	TOTAL UNIT PRICE (Col.3 + Col.4)	COST OF CONSTRUCTION (Col.1 x Col.5)	COST TO REMOVE I UNITS (Col.1 x Col.5)	UNIT VALUE (Table C of Contract)	TOTAL (Col.1 x Col.8)
1	2	3	4	5	6	7	8	9
2	IVA5–2	23.51				47 02	36 78	73.56
4	IVA6	34.58				138.32	60.25	241.00
3	IVC1	23.51				70.53	45 42	136.26
1	IVC2	45.65				45 65	28.68	28 68
1	IVC3	35 96				35.96	84 47	84 47
[illegible]	[illegible]C4–1	73.31				219 93	186.01	558.03
[illegible]	[illegible]C5	30 43				60.86	79 74	159 48
[illegible]	[illegible]C7	45 65				45 65	122.47	122.47
2	[illegible]C7–1	53.94				107 88	136.22	272.44
2	IVC8	102.36				204.72	215 04	430.08
1	IVC8–3	110 66				110 66	260 93	260 93
7	IVM5–2	4 15				29 05	7.20	50 40
32	IVM5–20	6.92				221.44	12.66	405 12
5	IVM5–4	4 15				20 75	7.55	37 75
7	IVM5–5	4.15				29.05	6.46	45.22
2	IVM5–9	11.07				22.14	42.00	84 00
30	I DEAD END CLAMP	30 00				900.00	10.50	315 00
2	I MIN MAX METER	50.00				100.00	0.00	0 00
25	ISOP	30 00				750 00	0.00	0 00
TOTAL					391,802.75	56,382.21		101 040.35

LABOR CHARGES FOR THE INSTALLATION AND REMOVAL OF SPECIAL EQUIPMENT ITEMS:

NEW CONSTRUCTI[illegible] & CONVERSIONS	15,571.75
REMOVALS	7,821.19
TOTALS	23,392.94

U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254.

SHEET OF SHEETS

DATE: April 11, 19X4

PROJECT DESIGNATION: State 99 County

BORROWER: County Electric Cooperative

ENGINEER: Big Engineering Company

CONTRACTOR: REO Construction Company

SUMMARY AND CLASSIFICATION OF MATERIALS RETURNED TO OWNER BY CONTRACTOR FROM "T" REMOVAL UNITS

AMOUNTS TO BE CREDITED TO CONTRACTOR FOR MATERIALS RETURNED					RETURNED MATERIALS DECLARED REUSABLE BY ENGINEER		
ITEM DESIG-NATION	DESCRIPTION OF MATERIAL	QUANTITY	ITEM VALUE TABLE D IN CONTRACT	TOTAL CREDIT TO CONTRACTOR (Col.12 x Col.13)	QUANTITY OF ITEMS	STOCK CARD ITEM PRICE	SALVAGE VALUE (Col.15x Col.16)
10	11	12	13	14	15	16	17
	400 AMP SWITCHES	3	250.34	751.02	3	250.34	751 02
a	PIN TYPE INSULATOR–14.4 KV	46	4 78	219 88	0		0 00
a	POLE TOP INSULATORS	423	1 82	769 86	0		0 00
aa	EYE NUTS	166	1.38	229 08	127	1.47	186 69
ab	THIMBLE EYE NUTS	5	1.65	8.25	0		0 00
ac	LIGHTNING ARRESTORS	6	23 71	142.26	0		0.00
af	SINGLE SHOT FUSE CUTOUTS	7	28.99	202.93	0		0 00
an	TRANSFORMER–1.5 KVA	2	81.74	163.48	2	81.74	163 48
an	TRANSFORMER–5 KVA	3	137 84	413.52	3	137.84	413.52
an	TRANSFORMER–10 KVA	7	220.95	1,546 65	7	220 95	1,546.65
an	TRANSFORMER–15 KVA	6	276 02	1 656.12	6	276.02	1,656.12
an	TRANSFORMER–7.5 KVA	1	178.56	178.56	1	178.56	178.56
ao	THIMPLE EYE BOLTS	10	1.20	12.00	0		0 00
ap	HOT LINE CLAMP	134	4 70	629 80	76	5 71	433 96
ar	K–10C	1	1.50	1.50	0		0 00
ar	K–17	59	1.50	88.50	0		0.00
ar	WIREHOLDER INSULATOR (K10)	45	1.50	67.50	0		0 00
av	#1/0 ACSR WIRE	6087	0 74	4,504.38	0		0 00
av	#2 ACSR WIRE	1281	0 87	1,114 47	0		0 00
av	#2 TFX WIRE	184	1.10	202.40	0		0 00
av	#2/0 ACSR WIRE	2535	0 74	1,875.90	0		0 00
av	#4 ACSR WIRE	2346	0.89	2,087 94	0		0 00
av	#4 TFX WIRE	17	1.02	17.34	0		0 00
av	#6 HDBC WIRE	11557	0 49	5,662.93	0		0.00
av	#6 TBWP WIRE (NEO)	172	0.53	91.16	0		0 00
av	SCRAP ALUMINUM	750	0.50	375 00	0		0 00
av	SCRAP COPPER	370	0.50	185 00	0		0 00
av	VARIOUS SCRAP WIRE	436	0.50	218.00	0		0 00
ax	COMBINATION UNITS	6	98 48	590 88	6	98 48	590.88
b	POLE TOP PIN	186	3.50	651.00	0		0 00
bo	ANCHOR SHACKLES	71	2.11	149.81	5	2.32	11 60
bz	DOUBLE UPSET BOLT	5	2.50	12.50	0		0 00
bz	SINGLE UPSET BOLTS	109	2.08	226.72	44	2.50	110 00
c	MACHINE BOLE – 6"	3	0 66	1.98	0		0 00

U.S. DEPARTMENT OF AGRICULTURE RU TILITIES SERVICE	SHEET OF SE
	DATE: April 11, 19X4 — PROJECT DESIG ON: State 99 County
	BORROWER: County Electric Cooperative
CONSTRUCTION INVENTORY (FOR LABOR AND MATERIAL CONTRACT)	ENGINEER: Big Engineering Company
INSTRUCTIONS – See reverse side of RUS Form 254.	CONTRACTOR: REO Construction Company

SUMMARY AND CLASSIFICATION MATERIALS RETURNED TO OWNER BY CONTRACTOR FROM "T" REMOVAL UNITS

AMOUNTS TO BE CREDITED TO CONTRACTOR FOR MATERIALS RETURNED					RETURNED MATERIALS DECLARED REUSABLE BY ENGINEER		
ITEM DESIG-NATION	DESCRIPTION OF MATERIAL	QUANTITY	ITEM VALUE TABLE D IN CONTRACT	TOTAL CREDIT TO CONTRACTOR (Col.12 x Col.13)	QUANTITY OF ITEMS	STOCK CARD ITEM PRICE	SALVAGE VALUE (Col.15x Col.16)
10	11	12	13	14	15	16	17
c	MACHINE BOLTS – 1 1/2"	12	0 66	7 92	12	0 46	5.52
c	MACHINE BOLTS – 10"	282	0 66	186 12	282	0 75	211.50
c	MACHINE BOLTS – 12"	139	0 66	91.74	139	0.81	112.59
c	MACHINE BOLTS –	22	0 66	14.52	22	0 92	20.24
c	MACHINE BOLTS	2	0.66	1.32	0		0 00
c	MACHINE BOLTS – 15"	6	0 66	3 96	0		0 00
c	MACHINE BOLTS – 8"	247	0 66	163 02	0		0 00
c	MACHINE BOLTS – 9"	238	0 66	157 08	238	0 75	178.50
cm	SEC. SPOOL INSULATOR	293	0.56	164 08	291	0 77	224 07
cm	SERV SPOOL INSULATOR	114	0 86	98 04	89	0 77	68.53
cu	CROSS ARM BRACE	199	3 85	766.15	0		0 00
cu	CROSS ARM BRACE (FIB)	4	9.35	37 40	0		0 00
cu	WOOD BRACE	3	3 85	11.55	0		0.00
d	SQUARE WASHERS	894	0 18	160 92	894	0.17	151 98
dd	ADAPTER PIN	7	1 10	7 70	0		0 00
dm	CLUSTER MOUNT	1	58 71	58 71	0		0 00
du	ALUMINUM EXTENSION LINK	172	0 00	0.00	0		0 00
f	CROSS ARM PIN	230	1 68	386 40	0		0 00
fo	T-BRACKET	3	10 00	30 00	0		0 00
g	CROSS ARMS – 8'	109	13 75	1 498.75	0		0 00
h	BOW BRACES	32	9.35	299.20	0		0.00
i	CROSS ARM CARR BOLTS	108	0.25	27 00	0		0 00
j	LAG SCREW	30	0 46	13.80	6	0 46	2.76
k	BELL INSULATORS – 10"	97	9 72	942.84	45	9 79	440.55
k	SUSPENSION BELL INSULATOR	400	5.52	2,208.00	301	5 63	1 694 63
l	#6 DEAD END CLAMP	3	6.52	19.56	0		0 00
l	PRIMARY D/E CLAMP (ALUM)	78	6.52	508.56	78	4 73	368.94
l	SEC. D/E CLAMP (ALUM)	64	6.52	417.28	5	4 73	23 65
m	SUSPENSION CLAMP (ANGLE)	13	4 19	54 47	0		0 00
n	DOUBLE ARMING BOLTS – 14"	1	1.31	1.31	0		0 00
n	DOUBLE ARMING BOLTS – 16"	38	1.31	49.78	0		0 00
n	DOUBLE ARMIONG BOLTS – 18"	69	1.31	90.39	69	1.92	132.48
n	DOUBLE ARMING BOLTS – 20"	35	1.31	45.85	9	1.88	16 92
n	DOUBLE ARMING BOLTS – 22"	22	1.31	28 82	13	2.22	28 86

U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET	OF	SHEETS
DATE: April 11, 19X4	PROJECT DESIGNATION: State 99 County	
BORROWER: County Electric Cooperative		
ENGINEER: Big Engineering Company		
CONTRACTOR: REO Construction Company		

SUMMARY AND CLASSIFICATION OF MATERIALS RETURNED TO OWNER BY CONTRACTOR FROM "T" REMOVAL UNITS

AMOUNTS TO BE CREDITED TO CONTRACTOR FOR MATERIALS RETURNED					RETURNED MATERIALS DECLARED REUSABLE BY ENGINEER		
ITEM DESIG–NATION	DESCRIPTION OF MATERIAL	QUANTITY	ITEM VALUE TABLE D IN CONTRACT	TOTAL CREDIT TO CONTRACTOR (Col.12 x Col.13)	QUANTITY OF ITEMS	STOCK CARD ITEM PRICE	SALVAGE VALUE (Col.15xCol.16)
10	11	12	13	14	15	16	17
n	DOUBLE ARMING BOLTS – 24"	8	1.31	10 48	6	2.64	15.84
n	DOUBLE ARMING BOLTS – 26"	1	1.31	1.31	0		0.00
o	EYE BOLTS – 10"	74	1.80	133.20	85	2.52	214.20
o	EYE BOLTS – 12"	16	1.80	28.80	0		0.00
o	EYE BOLTS – 14"	9	1.80	16.20	0		0 00
o	EYE BOLTS – 6"	19	1.80	34.20	0		0.00
o	EYE BOLTS – 8"	197	1.80	354 60	146	2.23	325.58
p	VIA4 CONN	3	1.79	5.37	0		0.00
s	SEC. RIGID CLEVIS (J–10)	63	0.53	33.39	33	3 45	113.85
s	SEC. SWINGING CLEVIS (J–6)	181	0.53	95 93	92	1.68	154.56
s	SERV RIGID CLEVIS (K–14)	4	0.53	2.12	0		0 00
s	SERV SWINGING CLEVIS (K–11)	118	0.53	62.54	81	1.64	132.84
sk	REGULATORS	3	2,750.00	8,250.00	1	2,750.00	2,750.00
u	3–BOLT GUY CLAMP	296	2.61	772.56	296	2.62	775.52
u	GUY CLAMP	1	2.61	2.61	0		0 00
v	GUY ATTACHMENTS	215	1.39	298.85	93	1.64	152.52
x	ANCHOR RODS	85	6.70	569.50	0		0.00
y	GUY STRAND WIRE – 3/8"	9195	0.18	1,655.10	0		0 00
zz	POLES – 25'	1	55.00	55 00	0		0 00
zz	POLES – 30'	2	58.68	117.36	0		0 00
zz	POLES – 35'	130	78.46	10 199.80	0		0.00
zz	POLES – 40'	63	111.65	7,033.95	0		0.00
zz	POLES – 45'	8	139.26	1,114.08			0.00
zz	POLES – 50'	1	150.00	150.00	0		0 00
be	OCR (50A)	1	1,244.23	1,244.23	1	1,244.23	1,244.23
be	OCR (OTHER)	4	190.25	761.00	4	190.25	761.00
	TOTAL			66 602.74			16,364.34

SALVAGE VALUE OF SPECIAL EQUIPMENT ITEMS RETURNED 8,713.56

NET VALUE OF SALVAGE RETURNED TO STOCK 7 650 78

U.S. DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	SHEET OF SHEETS
	DATE: April 11 19X4 — PROJECT DESIGNATION: State 99 County
	BORROWER: County Electric Cooperative
CONSTRUCTION INVENTORY (FOR LABOR AND MATERIAL CONTRACT)	ENGINEER: Big Engineering Company
INSTRUCTIONS – See reverse side of RUS Form 254	CONTRACTOR: REO Construction Company

TABULATION OF NET AMOUNT OF MATERIALS FURNISHED BY OWNER

ITEM DESIG-NATION	DESCRIPTION OF MATERIAL	QUANTITY	ACTUAL COST TO OWNER: UNIT COST	ACTUAL COST TO OWNER: EXTENDED COST (Col.20 x Col.21)	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT PRICE: UNIT PRICE	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT PRICE: EXTENDED COST (Col.20 x Col.23)	EXCESS OF COL. 24 OVER COL. 22
18	19	20	21	22	23	24	25
a	PIN TYPE INSULATORS –14.4	40	5 05	202.00	4 78	191.20	(10.80)
a	PIN TYPE INSULATORS –14.4	896	4 43	3 969.28	4 78	4,282.88	313 60
a	POLE TOP INSULATOR–14.4	48	5.35	256.80	9 72	466.56	209 76
ae	18 KV ARRESTER	37	38 11	1,410 07	23 71	877.27	(532.80)
ae	18 KV ARRESTER	3	38.32	114 96	23 71	71 13	(43 83)
ae	9 KV ARRESTER	13	24.22	314 86	23 71	308.23	(6.63)
af	100 AMP CUTOUT	60	36.05	2,163 00	28 99	1 739 40	(423 60)
af	600 AMP DISCONNECT SWITCH	3	209.55	628.65	122.30	366 90	(261 75)
af	600 AMP DISCONNECT SWITCH	3	108.60	325 80	122.30	366 90	41 10
ap	HOT LINE CLAMP	15	8 17	122.55	8.17	122.55	0 00
av	#A/0 ACSR WIRE	3,576	0 92	3,289 92	0 74	2,646.24	(643 68)
av	#A/0 ACSR WIRE	35,810	0 86	30 796 60	0 74	26 499 40	(4,297.20)
av	#1/0 TPX WIRE	428	1.14	487 92	1.02	436.56	(51.36)
av	#2 ACSR WIRE	1,180	0 97	1 149 07	0 87	1 027 00	(120 07)
av	#2 ACSR WIRE	5,685	0 90	5 116.50	0 87	4 945 95	(170.55)
av	#2 ACSR WIRE	1,195	0 93	1,111.35	0 87	1,039 65	(71 70)
av	#2 TPX WIRE	841	1.23	1 034 43	1 10	925 10	(109.[illegible])
av	#2 TPX WIRE	290	1.56	452.40	1.10	319.00	(133 [illegible])
av	#2/0 TPX WIRE	92	1.20	110 40	1.10	101.20	(9 [illegible])
av	#336 ACSR WIRE	539	0 79	425 81	0 91	490 49	64 68
av	#336 ACSR WIRE	20,227	0 94	19 013.38	0 91	18 406.57	(606.81)
av	#4 ACSR WIRE	100	1 10	110 00	0 89	89 00	(21.00)
av	#4 TPX WIRE	105	1.19	124 95	1.02	107 10	(17 85)
bv	#4 ARMOR RODS	42	0.36	15 12	0.36	15 12	0 00
bx	#2/0 AUTO SLEEVE	6	10 69	64 14	10 69	64 14	0 00
bx	#2/0 AUTO SLEEVE	4	11 18	44.72	11 18	44 72	0 00
c	1/2 X 2" BOLTS	28	0 63	17 64	0 63	17 64	0 00
cg	3 PHASE 25 KV H SWITCH	1	1 876.16	1,876.16	1876 16	1 876 16	0 00
cr	ANGLE BRACKET	2	7 45	14 90	7 45	14 90	0 00
cr	ANGLE BRACKET	3	5 71	17.13	5 71	17 13	0 00
cu	28" X–ARM BRACES–WOOD–FR	220	3.22	708.40	3 85	847 00	138.60
cu	28" X–ARM BRACES–WOOD–FR	5	3 17	15.85	3.85	19.25	3 40
cu	28" X–ARM BRACES–WOOD–FR	50	3 97	198.50	3 85	192.50	(6.00)
cu	28" X–ARM BRACES–WOOD–FR	5	3.86	19.30	3 85	19.25	(0 05)

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U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

CONSTRUCTION INVENTORY
(FOR LABOR AND MATERIAL CONTRACT)

INSTRUCTIONS – See reverse side of RUS Form 254

SHEET	OF SHEETS
DATE April 11 19X4	PROJECT DESIGNATION State 99 County
BORROWER County Electric Cooperative	
ENGINEER Big Engineering Company	
CONTRACTOR REO Construction Company	

TABULATION OF NET AMOUNT OF MATERIALS FURNISHED BY OWNER

ITEM DESIG-NATION	DESCRIPTION OF MATERIAL	QUANTITY	ACTUAL COST TO OWNER UNIT COST	ACTUAL COST TO OWNER EXTENDED COST (Col.20 x Col.21)	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT PRICE UNIT PRICE	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT PRICE EXTENDED COST (Col.20 x Col.23)	EXCESS OF COL. 24 OVER COL. 22
18	19	20	21	22	23	24	25
cu	60" X-ARM BRACES-WOOD-FR	20	9 63	192.60	9.35	187 00	(5 60)
cu	60" X-ARM BRACES-WOOD-FR	69	8.06	556.14	9.35	645 15	89 01
cu	60" X-ARM BRACES-WOOD-FR	5	11.02	55 10	9.35	46 75	(8.35)
cu	60" X-ARM BRACES-WOOD-FR	20	10.09	201.80	9.35	187.00	(14 80)
cv	#336 N/P SLEEVE	1	14 99	14 99	14 99	14 99	0 00
cv	#4 NEUTRAL SLEEVE	7	1.50	10.50	1.50	10.50	0.00
dd	ADAPTER THIMBLE	15	2.05	30 75	2.05	30 75	0.00
dm	CLUSTER MOUNT	1	61 19	61.19	61.19	61 19	0.00
dm	CLUSTER MT FOR RECLOSER	1	44 61	44 61	44 61	44 61	0 00
ea	25 KV INSULATOR	5	22.40	112.00	22.40	112.00	0 00
ea	INSULATOR – 25 KV	3	22.41	67.23	8.25	24 75	(42.48)
eb	P T. INS. BRKT. W/STOB BOLT	3	13.37	40 11	13.37	40 11	0 00
eb	POLE TOP BRACKET	3	10 64	31.92	10 64	31.92	0.00
eb	P T. INS. BRKT.	2	10 64	21.28	10 64	21.28	0 00
eu	54" STRAIN INSULATOR	7	15 45	108 15	15 45	108.15	0 00
eu	54" STRAIN INSULATOR	5	13 90	69.50	13 90	69.50	0 00
f	CROSSARM FINE-14.4 KV	47	5 46	256.62	5 46	256.62	0.00
f	SADDLE PINS-14.4 KV	23	7 43	170 89	7 43	170 89	0 00
f	SADDLE PINS-14.4 KV	210	6.54	1,373 40	7 43	1,560.30	186.90
fn	CUTOUT BRACKET	2	9.37	18.74	9.37	18 74	0.00
fn	CUTOUT BRACKET	3	9 77	29.31	9 77	29.31	0 00
fn	X-ARM MT BRACKET	100	2.94	294.00	2.94	294 00	0 00
fn	X-ARM MT. BRACKET	15	2.35	35.25	2.35	35.25	0 00
fn	X-ARM MT. BRACKET	15	4.31	64 65	4 31	64 65	0 00
g	10' CROSSARMS	10	19.57	195 70	17 85	178.50	(17.20)
g	10' CROSSARMS	1	18 87	18 87	17 85	17.85	(1.02)
g	10' CROSSARMS	4	16.38	65.52	17.85	71 40	5.88
g	8' CROSSARMS	50	16.48	824 00	13 75	687.50	(136.50)
g	8' CROSSARMS	290	12.96	3 758.40	13 75	3 987.50	229 10
g	8' CROSSARMS	12	16 83	201.96	13 75	165 00	(36.96)
k	9" BELL INSULATOR	144	9 79	1,409 76	9 72	1,399 68	(10 08)
k	9" BELL INSULATOR	120	9.36	1,123.20	9 72	1 166 40	43.20
k	9" BELL INSULATOR	60	8 99	539 40	9 72	583.20	43 80
k	9" SUSPENSION INSULATOR	360	8.96	3,225 60	9 72	3 499.20	273 60

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U.S. DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE CONSTRUCTION INVENTORY (FOR LABOR AND MATERIAL CONTRACT)	SHEET OF SHEETS
	DATE: April 11, 19X4 — PROJECT DESIGNATION: State 99 County
	BORROWER: County Electric Cooperative
	ENGINEER: Big Engineering Company
INSTRUCTIONS – See reverse side of RUS Form 254	CONTRACTOR: REO Construction Company

TABULATION OF NET AMOUNT OF MATERIALS FURNISHED BY OWNER

ITEM DESIG-NATION	DESCRIPTION OF MATERIAL	QUANTITY	ACTUAL COST TO OWNER: UNIT COST	ACTUAL COST TO OWNER: EXTENDED COST (Col.20 x Col.21)	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT. PRICE: UNIT PRICE	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT. PRICE: EXTENDED COST (Col.20 x Col.23)	EXCESS OF COL. 24 OVER COL. 22
18	19	20	21	22	23	24	25
k	9" SUSPENSION INSULATOR	290	8.99	2,607 10	9 72	2,818.80	211.70
m	#336 ANGLE SHOES	7	7 45	52.15	7 45	52.15	0 00
p	#6 SPLIT BOLTS	25	12.00	300 00	12.00	300.00	0.00
p	E5 2W 2W CONN.	21	0 77	16 17	0 77	16 17	0.00
p	SNLO25R CONNECTOR	14	12.82	179 48	12.82	179 48	0 00
o	DOUBLE UPSET BOLTS	12	1.22	14 64	1.22	14 64	0.00
an	TRANSFORMER–10 KVA CONV	2	187.16	374.32	187.16	374.32	0 00
an	TRANSFORMER–15 KVA CONV	2	177 12	354.24	194.73	389.46	35.22
an	TRANSFORMER–25 KVA CONV	1	214.46	214.46	268.18	268.18	53.72
an	TRANSFORMER–15 KVA CSP	6	237.12	1 422.72	276 02	1,656.12	233 40
an	TRANSFORMER–25 KVA CSP	3	238.66	715.98	301.41	904 23	188 25
an	TRANSFORMER–10 KVA CSP (14.4)	3	444 82	1,334.46	444.82	1,334.46	0 00
an	TRANSFORMER–15 KVA CSP (14.4)	3	556.91	1 670.73	556.91	1 670.73	0.00
an	TRANSFORMER–25 KVA CSP (14.4)	1	647 41	647.41	647 41	647.41	0.00
zz	POLE 30–6	2	47 08	94 16	47 48	94.96	0.80
zz	POLE 30–6	1	47.20	47.20	47 68	47 68	0 48
zz	POLE 35–4	1	83.02	83.02	83.82	83.82	0.80
zz	POLE 35–5	4	83.02	332.08	71.24	284 96	(47 12)
zz	POLE 35–5	6	74.34	446.04	62.14	372.84	(73.20)
zz	POLE 35–5	14	70.55	987.70	71.24	997.36	9 66
zz	POLE 35–6	1	61.54	61.54	62.14	62.14	0 60
zz	POLE 40–3	4	118.04	472.16	119 18	476 72	4.56
zz	POLE 40–4	1	107 48	107 48	111.64	111.64	4 16
zz	POLE 40–4	112	110.57	12,383 84	111.64	12,503 68	119.84
zz	POLE 40–5	3	89 46	268.38	90.32	270 96	2.58
zz	POLE 40–5	7	89 45	626.15	90.32	632.24	6 09
zz	POLE 45–3	9	150 94	1,358.46	152.41	1,371.69	13.23
zz	POLE 45–4	43	120 82	5,195.26	121.99	5,245.57	50.31
zz	POLE 45–4	1	121.02	121.02	121.99	121 99	0 97
zz	POLE 50–3	22	160 42	3,529.24	161.98	3,563.56	34.32
zz	POLE 50–4	1	144.37	144.37	145.29	145.29	0 92
zz	POLE 50–4	20	143 89	2,877.80	145.29	2,905 80	28 00
zz	POLE 50–4	1	143 88	143 88	145.29	145.29	1.41
zz	POLE 55–3	5	221.14	1 105 70	223.29	1 116.45	10 75

8 29

U.S. DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE CONSTRUCTION INVENTORY (FOR LABOR AND MATERIAL CONTRACT)	SHEET OF SHEETS	
	DATE April 11, 19X4	PROJECT DESIGNATION State 99 County
	BORROWER County Electric Cooperative	
	ENGINEER Big Engineering Company	
INSTRUCTIONS – See reverse side of RUS Form 254	CONTRACTOR REO Construction Company	

TABULATION OF NET AMOUNT OF MATERIALS FURNISHED BY OWNER

ITEM DESIG-NATION	DESCRIPTION OF MATERIAL	QUANTITY	ACTUAL COST TO OWNER: UNIT COST	ACTUAL COST TO OWNER: EXTENDED COST (Col.20 x Col.21)	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT. PRICE: UNIT PRICE	AMOUNT CHARGEABLE TO CONTRACTOR AT CONT. PRICE: EXTENDED COST (Col.20 x Col.23)	EXCESS OF COL. 24 OVER COL. 22
18	19	20	21	22	23	24	25
22	POLE 55–3	1	221.15	221.15	223.29	223.29	2.14
	50 AMP FUSELINKS	27	1.63	44.01	1.63	44.01	0.00
	DEADEND CROSSBAR	1	41 92	41.92	41 92	41 92	0.00
	FUSELINK	47	1.63	76 61	1.63	76 61	0.00
	RECLOSER HANGER	4	20 92	83 68	20 92	83 68	0 00
be	OCR (50E)	3	1,244.23	3,732.69	1244.23	3,732.69	0.00
be	OCR (OTHER)	9	190.25	1,712.25	190.25	1,712.25	0.00
TOTAL				137 147.35		131,870 97	(5,274.38)
SPECIAL EQUIPMENT COSTS:				12,179.26		12,689.85	510.59
NET COSTS				124,968 09		119 181 12	(5 784 97)

SCHEDULE OF SPECIAL EQUIPMENT REUSED

Assembly Unit (a)	Units Installed (RUS Form 254a) (b)	Units Removed (RUS Form 254a) (c)	Units Returned (RUS Form 254b) (d)	Units Furnished By Borrower (RUS Form 254c) (e)	Units Furnished By Contractor (f)	Units Available For Reuse (Column c–d) (g)	Units Reused (Column b–e–f) (h)	Unit Price (Table D) (i)	Value of Special Equipment Reused (Column h x i) (j)
10CONV	3	1	0	2	0	1	1	$ 220 95	$ 220 95
10CSP	32	39	7	0	0	32	32	220 95	7,070 40
10(210)	1	1	0	0	0	1	1	220 95	220 95
10V–CONV	1	1	0	0	0	1	1	455 09	455 09
10V–CSP	18	21	6	3	0	15	15	444 82	6,672 30
15CONV	3	1	0	2	0	1	1	194 73	194 73
15CSP	22	16	0	6	0	16	16	276 02	4,416 32
15(210)	1	1	0	0	0	1	1	276 02	276 02
15(310)	3	3	0	0	0	3	3	276 02	828 06
15V–CSP	8	5	0	3	0	5	5	556 91	2,784 55
25(210)	3	3	0	0	0	3	3	368 18	1,104 54
25CONV	1	0	0	1	0	0	0	0	0
25CSP	7	4	0	3	0	4	4	301 41	1,205 64
25V–CSP	2	1	0	1	0	1	1	647 41	647 41
37CSP	2	2	0	0	0	2	2	370 52	741 04
50(210)	1	1	0	0	0	1	1	458 83	458 83
5CSP	7	10	3	0	0	7	7	137 84	964 88
7CSP	1	2	1	0	0	1	1	178 56	178 56
TOTALS	116	112	17	21	0	95	95		$ 28,440 27

Note Table D does not include a unit price for a 50KVA transformer The unit price was estimated at $458 83

STATE 99 COUNTY
DISTRIBUTION CONSTRUCTION UNITS – LINE CHANGES
TABLE D – VALUE OF MATERIAL ITEMS CREDITABLE TO BIDDER

RUS Item Letter Designation*	Description of Material Item	Item Value
a	Insulator PT 7 2 KV	$ 1 82
a	Insulator PT 14 4	4 78
b	Pole Top Pin	3 50
c	Machine Bolt	66
d	Washer	18
f	Steel Crossarm Pin	1 68
f	Crossarm Pin Clamp	7 43
g	Crossarm 8'	13 75
g	Crossarm 10'	17 85
g	5' Steel Insulated Bracket	18 00
i	Bolt, Carriage	25
j	Lag Screw	46
k	Suspension Insulator 7 2KV	5 52
k	Suspension Insulator 14 4KV	9 72
l	Deadend Clamp	6 52
m	Suspension Clamp	4 19
n	Double Arming Bolt	1 31
o	Eye Bolt	1 80
p	Connectors	1 79
q	Bolt, Double Upset	53
s	Clevis, Swing	1 85
u	Clamp, 3 Bolt	2.61
v	Guy Attachment	1 39
x	Anchor Rod	6 70
y	Guy Stand, Ft.	18
aa	Eye Nut	1 38
ab	Nut, Thimble Eye	1 65
ae	Lightning Arrestor 9 KV	23 71
af	Cutout, 15KV	28 99
af	Cutout, Loadbreak 18KV	122.30
an	Transformers 7 2 – 5KVA CSP	137 84
	7 KVA CSP	178 56
	10 KVA CSP	220 95
	15 KVA CSP	276 02
	25 KVA CSP	301 41
	37 5 KVA CSP	370 52
	15 KVA CONV	194 73
	25 KVA CONV	368 18
an	Transformers 14 4 – 10 KVA CSP	444 82
	15 KVA CSP	556 91
	25 KVA CSP	647 41
	10 KVA CONV	455 09

STATE 99 COUNTY
DISTRIBUTION CONSTRUCTION UNITS – LINE CHANGES
TABLE D – VALUE OF MATERIAL ITEMS CREDITABLE TO BIDDER

RUS Item Letter Designation*	Description of Material Item	Item Value
ao	Thimble Eye Bolt	$ 1 20
ap	Hot Line Clamp	4 70
as	Clevis, Swing, Insulated	2.71
at	Guy Guard	4 24
av	Conductor 2 Triplex, LB	1 10
	4 Triplex, LB	1 02
	1/0 Triplex, LB	1 02
	2/0 ACSR, LB	74
	6 WPCU, LB	53
	8 WPCU, LB	53
	1/0 ACSR, LB	74
	4 ACSR, LB	89
	2 ACSR, LB	87
	6 HDCU, LB	49
	8 ACWC, LB	50
	6 ACWC, LB	45
	4 HDCU, LB	44
be	Oil Circuit Recloser	190 25
be	Oil Circuit Recloser – 15A, 35A, 50A	1,244 23
bh	Service Clevis with Spool	1 89
bh	Clamp Loop Dead End	2.00
bj	Guy Hook	65
bk	Guy Plate	60
bo	Anchor Shackle	2.11
bs	Bolt, Single Upset	2.08
cd	Angle Shoe, 336	3 25
ck	Anchor Rod Bond Clip	57
cm	Spool Insulator	86
cu	Wood Brace 28" PR	3 85
cu	Wood Brace 60" PR	9 35
da	Bracket, Neutral Insulated	2.71
dd	Insulator Adapter, 7 2KV	1 10
dm	Cluster Mount Bracket	58 71
ek	Locknut	10
fi	Hot Line Connector	3 78
ax	Cutout and Arrestor Combination, 18 KV	98 48
	Security Light	45 00
zz	Poles 30'	58 68
	35'	78 46
	40'	111 65
	45'	139 26
	50'	150 00

833

STATE 99 COUNTY
DISTRIBUTION CONSTRUCTION UNITS – LINE CHANGES
TABLE D – VALUE OF MATERIAL ITEMS CREDITABLE TO BIDDER

RUS Item Letter Designation*	Description of Material Item	Item Value
	3 Wire Rack	$ 4 50
	Fiberglass Guy Strain Insulator	13 50
sk	By–Pass Switch	250 34
ar	Wireholder	1 50
	Capacitor	292 54
dy	Eyebolt, Double Arming	1 80
ec	Stand–Off Bracket	6 00
ea	Post–Type Insulator	8 25
fd	Hanger, Cluster Mount	15 00
sc	Regulators	2,750 00

* See the "List of Materials Acceptable for Use on Systems of RUS Borrowers"

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RETIREMENT WORK ORDER

Work Order No 87301X

Location XYZ County
Retirement-No Replacement
Retirement-Sys Improve X
Retirement-Replacements

Related W O No
Related W O No

Work Started
Work Completed
Primary Miles Retired
Sec & Serv Miles Retired

Description of Work Contract Construction and Removal, Distribution Line
REO Construction Company, April 11, 19X4

FROM STAKING SHEET NO	ACCT NO	DEBITS: Original Cost Property Retired				DEBITS: Cost of Removal					CREDIT	NET LOSS DUE TO RETIREMENT
		RECORD UNIT	QUANTITY	UNIT COST	TOTAL	DATE	FOLIO REFERENCE	DIRECT LABOR	OVERHEAD	TOTAL	SALVAGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	364	Anchor Guy	95	31 80	3 021 00							
	364	Crossarm	131	45 15	5 914 65							
	364	Poles-35'										
	364	& Under	119	58 51	6 962 69							
	364	40-45	68	104 82	7 127 76							
	364	50 and Over	1	243 92	243 92							
	365	Ltg Arrester	10	131 58	1,315 80							
	365	Cut Out	21	93 00	1,953 00							
	365	Ground	264	17 96	4 741 44							
	365	Stg of Ins	270	31 72	8 564 40							
	365	#6 HDUC	145 438	40 01	5 818 97							
	365	#4 ASCR	35 011	77 91	2,727 71							
	365	#6 CWLD	0 230	49 98	11 50							
	365	#3 HDCU	0 265	319 21	84 59							
	365	#2 ACSR	12 001	107 49	1 289 99							
	365	#1/0 ASCR	41 918	216 34	9 068 54							
	365	#2/0 ACSR	13 798	200 07	2,760 57							
	365	Comb Unit	4	224 58	898 32							
	368	Comb Unit	16	224 58	3 593.28							
	369	3-#2 TPX	11	82 33	905 63							
	369	2-#8WP	2	14 21	28 42							
	369	3-#6WP	2	23 14	46 28							
	369	3-#8WP	1	23 14	23 14							
	371	Sec. Light	16	115 44	1 847 04							
TOTALS					68 948 63			48,561 02		48,561 02	13 648 12	103,861 53

Credit Account No									
	353		357		365	39,234 82	369	17	
	354		358		366		371	04	
	355		362		367		372		
	356		364	23 270 02	368	3 593 28			

APPROVED BY _____ DATE _____

	Unitization And Distribution To Plant Accounts						Month of April 19X4				Inventory No.					
Acct. No	Record Unit (1)	No of Units (2)	Unit Standard Costs (3)		Total Standard Costs (4)		Total Actual Costs ("C" x Col 4) (5)		Adjusted Unit Costs (Gross) (6)		Contributions In Aid Of Construction (7)		Total Net Costs (Col 5–Col. 7) (8)		Adjusted Unit Costs (Net) (Col. 8/Col 2) (9)	
362																
	Anchor Guy	200	76	05	15,210	00	20,246	78								
	Crossarm	395	58	72	23,194	40	30,875	20								
	Poles 35' & Under	33	155	02	5,115	66	6,809	71								
364	40' – 45'	177	222	29	39,345	33	52,374	49								
	50' & Over	48	296	83	14,247	84	18,966	00								
	Cluster Mount	1	174	59	174	59	232	41								
	Total Account 364						129,504	58								
	Lightning Arrester	40	77	93	3,117	20	4,149	46								
	Cutout	67	77	93	5,221	31	6,950	34								
	Ground	258	61	42	15,846	36	21 093	87								
	String Of Insulators	258	69	61	17,959	38	23,906	61								
	Bypass Switch	6	267	74	1,606	44	2,138	41								
	No 4 ACSR	8 139	234	20	1,906	15	2,537	37								
365	No 6 HDBC	4.228	200	00	845	60	1,125	62								
	1/O ACSR	254.634	291	88	74,322	57	98,934	41								
	No 2 ACSR	76 608	268	79	20,591	46	27 410	31								
	No 2 TPX	4.804	569	72	2,736	93	3,643	27								
	1/O TPX	0 68	702	60	477	77	635	98								
	No 336.4 ACSR	54.516	599	47	32,680	71	43,502	89								
	Combination Unit	5	182	68	913	40	1,215	87								
	Capacitor Cluster Mount	3	91	33	273	99	364	72								
	Total Account 365						237 609	12								
366																
	Total Account 366															
367	600 Amp Switch	6	285	66	1,713	96	2,281	54								
	Total Account 367						2,281	54								
368	Combination Unit	3	224	58	673	74	896	85								
	Total Account 368						896	85								
369	3–W #2 TPX	23	232	29	5,342	67	7,111	89								
	Total Account 369						7 111	89								
371	Security Light	6	115	44	692	64	922	01								
	Total Account 371						922	01								
		Total Account														

A. Total Standard Cost 284,210 11

B. Total Actual Cost. Dr Plant Accounts––Cr Account 107.2 378,325 99

C. Total Actual Cost to Standard Cost Ratio
(B Less Acct. 362 / A) 1.33114895

D Contributions In Aid Of Construction. Dr Account 107.2––Cr Plant Accounts

USDA–RUS

INVENTORY OF WORK ORDERS

No funds involved may be requisitioned unless a completed application Form 219 has been received (7 U.S.C. 901 et seq.)

FORM APPROVED
OMB No. 1572–0019
EXPIRES 02/28/96

1. INVENTORY NO: 9–89 (CC#12X)
2. MONTH ENDING: APRIL 19X4
3. SYSTEM DESIGNATION: State 99 County
4. NAME OF BORROWER: County Electric Cooperative

INSTRUCTIONS. *Prepare 2 copies of this form. Forward 1 copy to the Rural Utilities Service, USDA, Washington, DC 20250. For detailed instructions see RUS Bulletin 1767B–1.*

740–C CODE: CODE NO	YEAR	WORK ORDER: CONSTRUCTION (1)	RETIREMENT (2)	BUDGET ITEM NO (3)	GROSS FUNDS REQUIRED: COST OF CONSTRUCTION (4)	COST OF REMOVAL IN SYSTEM IMPROVEMENTS (5)	DEDUCTIONS: ORIGINAL COST OF UNITS RETIRED IN ORDINARY REPLACEMENTS (6)	SALVAGE RELATING TO: SYSTEM IMPROVEMENTS ONLY (7)	RETIREMENTS WITHOUT REPLACEMENT (8)	CONTRIBUTIONS IN AID OF CONSTRUCTION AND PREVIOUS APPROVALS (9)	LOAN FUNDS SUBJECT TO ADVANCE BY RUS (10)
		87301	87301X	1							
		Total Contract #12X			391,802.75	56,382.21		34,437.61		(1) 233,938.60	179,808 75
		Less OFM at CT Prices			(131,870 97)						(131,870.97)
					259,931 78						
		Plus: Net Amount OFM at actual cost less special equipment			124,966.09					(1) 131,870.97	(6,904.88)
		Materials Salvage						7,650.78			(7,650.78)
		Less: Special Equipment Installation (labor)			(14,852.49)						(14,852.49)
		Materials (Re–Used)			28 440.27)			(28,440.27)			0.00
		Removal (labor)				(7,821.19)					(7,821 19)
		Net Contract			1,605.11	48,561.02		13,648.12		365,809.57	10,708.44
		87302		1							
		Force Account Costs Associated with CC#12X									
		Misc. Labor & Overhead			36,720.88						36,720.88
		(1) Amounts approved for advance on RUS Form 505, dated July 16, 1989									
TOTAL					378,325.99	48,561.02	0.00	13,648.12	0 00	365,809.57	47 429.32

SUMMARY BY BUDGET ITEMS

Item No.	740–C Code	Amount
1	301	89,461.00
1	302	37,519.20
1	303	100,980.50
1	304	185,278.19
TOTAL		413,238.89

ENVIRONMENTAL CERTIFICATION – *FOR MINOR PROJECT 219 ONLY*

1 ☐ *We certify that construction reported on the above listed work orders (except certification "2" below), is a categorical exclusion of a type described in 7 CFR 1794.31 (b) which normally does not require preparation of a Borrower's Environmental Report.*

2 ☐ *We certify that construction reported on work orders _____ above, is a categorical exclusion of a type that normally requires a Borrower's Environmental Report which is attached.*

DATE | SIGNATURE *(Manager)*

BORROWER CERTIFICATION – *We certify that the costs of construction shown are the actual costs and are reflected in the general accounting records. We further certify that funds represented by advances requested have been expended in accordance with the purposes of the loan, the provisions of the loan contract and mortgage, and RUS bulletins and the Code of Federal Regulations relative to the advance of funds for work order purposes.*

DATE | SIGNATURE *(Manager)*

DATE | SIGNATURE *(Board Approval)*

ENGINEERING CERTIFICATION – *I hereby certify that sufficient inspection has been made of the construction reported by this inventory to give me reasonable assurance that the construction complies with applicable specifications and standards and meets appropriate code requirements as to strength and safety. This certification is in accordance with acceptable engineering practice.*

INSPECTION PERFORMED BY | FIRM

LICENSE NUMBER | SIGNATURE OF LICENSED ENGINEER

RUS FORM 219 (Rev 88) facsimile – computer generated form

Note In those cases where advances have been received prior to the preparation of the final RUS Form 219 those advances should be reported in column 9 Contributions in Aid of Construction and Previous Approvals.

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GOVERNMENTAL

RELATIONS

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GOVERNMENTAL RELATIONS

GOVERNMENTAL RELATIONS

- Co-Ops Usually Governed By Member Elected Board of Directors
- Some Co-Ops Are Governed By State Public Service Commissions (PSC)
- Federally Governed by Rural Utility Service (RUS formerly REA)
- Generally Not Regulated by Federal Energy Regulatory Commission (FERC) Because of RUS

GOVERNMENTAL RELATIONS

- Distinguishable Characteristics of Co-Ops
  - Size
  - Regulatory Environment
  - Organization
  - Nonprofit Operation
  - Taxation
  - Density

GOVERNMENTAL RELATIONS

- Regulatory Environment
  - Financing
    - RUS (Rural Utility Service)
    - NRUCFC (National Rural Utilities Cooperative Finance Corporation)
    - FFB (Federal Financing Bank)
    - CoBank (Cooperative Bank)
  - Debt Guaranteed by RUS

GOVERNMENTAL RELATIONS

- RUS IS THE SINGLE MOST IMPORTANT FACTOR IN FINANCIAL AND REGULATORY AFFAIRS

GOVERNMENTAL RELATIONS

- Regulation
  - Important Cases Have Held That Co-Ops Are <u>Not</u> Public Utilities, Therefore Not Subject to Regulation by FERC
  - Additionally Rates are Not Subject to State Regulatory Agencies - Most of the Time
  - Rates Are Determined by Board of Directors
    - ***<u>HOWEVER</u>***.....

One Half of Co-Ops Are Now Regulated By State Regulatory Agencies

BUT

RUS Still Governs Through the Mortgage Covenants

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Unknown Regulatory Issues

- Some Co-Ops Have Bought Out of RUS
- Deregulation of the Electric Industry Will Affect Regulatory Bodies
  - PSC
  - Boards
  - FERC
- Co-Ops Have a Slight Advantage Today With Their Own Board

DAY 3

8 00 - 9 00	Activity Based Management Overview	Mr Billy Ussery
9 00 - 10 15	Performance Measurement/Project Management	Mr Billy Ussery
10 15 - 10 30	Break	
10 30 - 12 00	Best Management Practices	Mr Billy Ussery
12 00 - 1 00	Lunch	
1 00 - 2 00	Performance Measurement	Mr Billy Ussery
2 00 - 3 00	Unit Cost Reporting	Mr Billy Ussery
3 00 - 3 15	Break	
3 15 - 5 00	Productivity Reporting	Mr Billy Ussery

ACTIVITY BASED

MANAGEMENT

OVERVIEW

OVERVIEW FOR DAY 3

Day 3

- Activity Based Management Overview
- Performance Measurement
- Project Management
- Unit Costs
- Benchmarking

Activity Based Management Overview

Activity Based Management Overview

Critical for the "New" Competitive Electric Industry

- Mergers, Restructuring And Regulation Changes require Better Costing and Management Concepts
- Utility Managers Must Have Relevant, Accurate Specific Information About Their Distribution Company

Activity Based Management Overview

- Distribution Company Managers Must:
  - Know What is Being Spent
  - Develop Efficient Systems and Processes
  - Measure Results of Systems
  - Make Decisions Based on Both Business Goals and Regulatory Requirements

Activity Based Management Overview

- Activity - A defined scope of work that produces a physical or informational result, uses a measurable set of resources and may have an identifiable driver (one or more business factors or event that causes the work to be performed)

» Accounting for Public Utilities - Matthew Bender & Co., Inc

Activity Based Management Overview

- Define The Activity
- Project Specific or Ongoing Activity
- Discrete Departmental Work or Cross-Functional Activity
- Defined Benefit or Intangible Benefit
- Cost Based Benefit or Investment Benefit

Activity Based Management Overview

- Examples of Activities
  - Install Commercial Services
  - Maintain Supervisory Control and Data Acquisition System (SCADA)
  - Update Distribution Maps
  - Expand Branch Office

Activity Based Management Overview

- One Possible Business Model

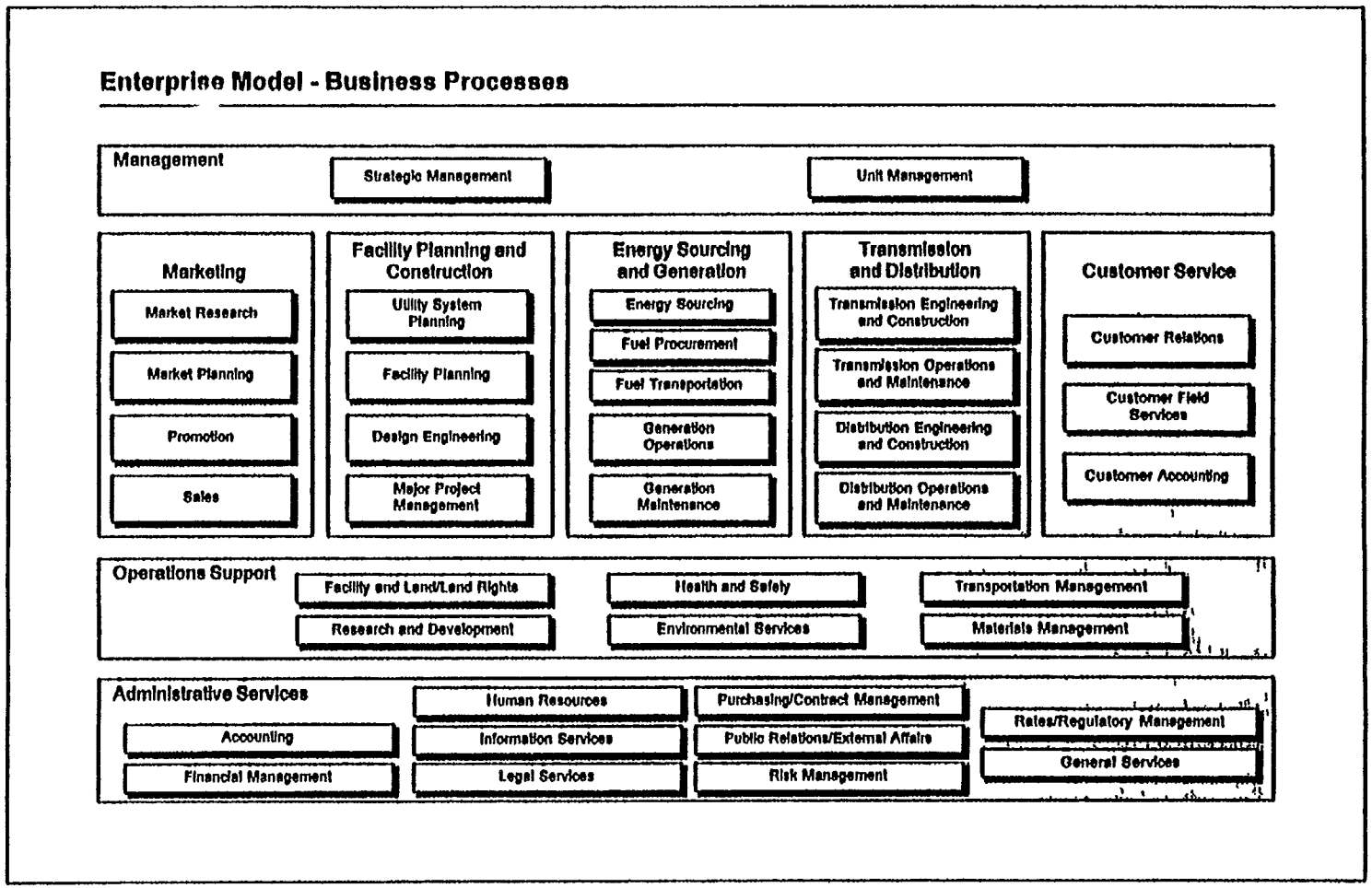

Enterprise Model - Business Processes
Management
Strategic Management
Unit Management
Marketing
Market Research
Market Planning
Promotion
Sales
Facility Planning and Construction
Utility System Planning
Facility Planning
Design Engineering
Major Project Management
Energy Sourcing and Generation
Energy Sourcing
Fuel Procurement
Fuel Transportation
Generation Operations
Generation Maintenance
Transmission and Distribution
Transmission Engineering and Construction
Transmission Operations and Maintenance
Distribution Engineering and Construction
Distribution Operations and Maintenance
Customer Service
Customer Relations
Customer Field Services
Customer Accounting
Operations Support
Facility and Land/Land Rights
Research and Development
Health and Safety
Environmental Services
Transportation Management
Materials Management
Administrative Services
Accounting
Financial Management
Human Resources
Information Services
Legal Services
Purchasing/Contract Management
Public Relations/External Affairs
Risk Management
Rates/Regulatory Management
General Services

Figure 15-3

Activity Based Management Overview

- Discussion of How "Installing Commercial Services" Crosses Several Blocks and Affects Many Areas

Activity Based Management Overview

- Develop a Set of Activities
- Identify the Business Processes
- Identify the Activities Related to Process
- Once These Key Parts are Identified - Costs Can be Reduced

PERFORMANCE

MEASUREMENT

PERFORMANCE MEASUREMENT

Project Management

Performance Measurement

- Critical for Today's Competitive Environment
- May Be Used As Incentive Pay
- Allows For Some Self Governing
- Generates Competition Among Workers
- Must Be Applied to Contractor Employees As Well

Performance Measurement Translates to Project Cost Management and Awareness

Project Cost Management

- Define the Activity
- Determine the Cost
- Look for Factors that Influence the Outcome
  - Both Positively
  - And Negatively

Project Cost Management

- Determine Acceptable Project Cost
- Determine Tolerances
- Ask Questions

PROJECT MANAGEMENT
Specifics

- Project Control
- Project Reporting System
- Large Projects
- Projects Other than Major Construction
- Flow of Data for Project Cost Management and Close Out

PROJECT MANAGEMENT
Project Control

- Three Dimensions
  - Achieve Project's Objective with Quality
  - Complete Projects on Schedule
  - Complete Project within Budget

PROJECT MANAGEMENT
Project Control And Cost Control

- Prepare a Realistic Budget to Monitor and Control Actual Costs
- Develop a Data Collection Process that Makes all Data Available on a Timely Basis so Changes Can be Implemented Before it is too late

PROJECT MANAGEMENT
Project Control And Cost Control

- Compare Actual to Budgeted at Appropriate Levels of the Project and Make Necessary Adjustments
- Large Projects or Lengthy Projects May Have to Include Forecasted Costs Over Months and Even Years

PROJECT MANAGEMENT
Project Reporting System

- Objectives
  - Project Management
  - Control Costs of Construction
  - Proper Accounting
    - Work In Progress
    - Closing and Unitizing Work Orders
    - Transferring to Plant Accounts
    - Commence Depreciating Over Useful Life

PROJECT MANAGEMENT
Four Basic Project Levels

- Budget Items
- Work Orders
- Work Breakdown Structures
- Master Project

PROJECT MANAGEMENT

- Budget Item
  - Highest Level of Project
  - Identified to Top Management
  - Budget Line Item
- Work Order
  - Define Scope of Work
  - Authorize Specific Budget Item
  - Usually Project Specific
  - May Have More Than One For Large Projects

PROJECT MANAGEMENT

- Work Breakdown Structure
  - Plan Work Scope
  - Estimate
  - Control Expenditures of Resources
  - Report Progress, Cost and Variances
- Master Project
  - Usually More Than One Work Order
  - May Represent Different Work Types for Same Project

Conceptual Design of a Project Management System

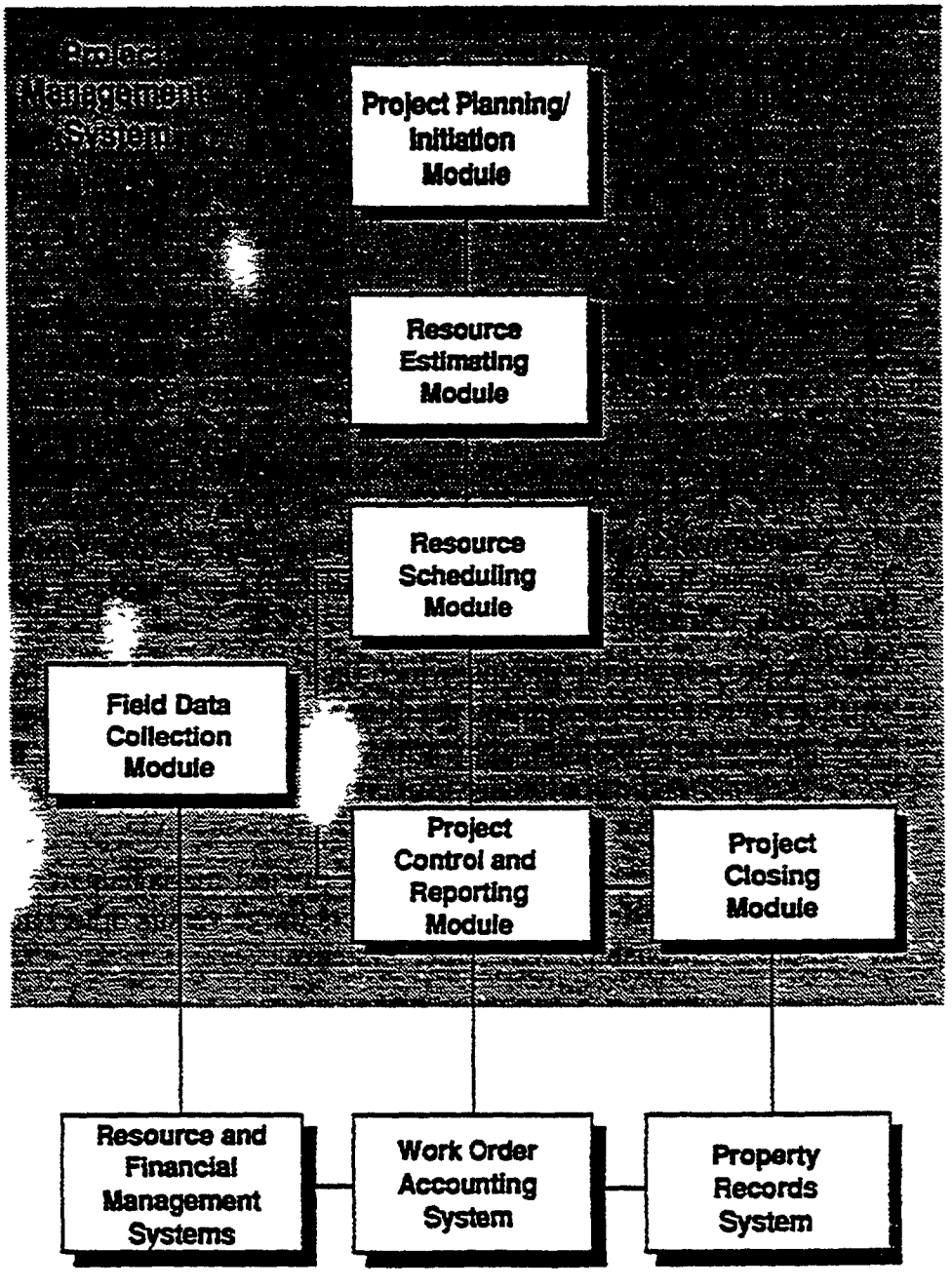


Figure 16-4

8 17

Project Management

- Project Reporting System
  - Project Initiation Module
  - Estimating Module
  - Resource Scheduling Module
  - Control and Reporting Module
  - Project Closing Module

Project Management

- Large Projects
  - Warrants Different Approach
  - Multi-Year Projects
  - Very High Cost Projects
  - Major External / Regulatory Oversight
  - Divide Into Work Breakdown Structures

Project Management

- Projects Other Than Major Construction
  - Usually Smaller In Scope
  - Represent a Large Number of Projects
  - Includes Maintenance Work
  - Special Projects

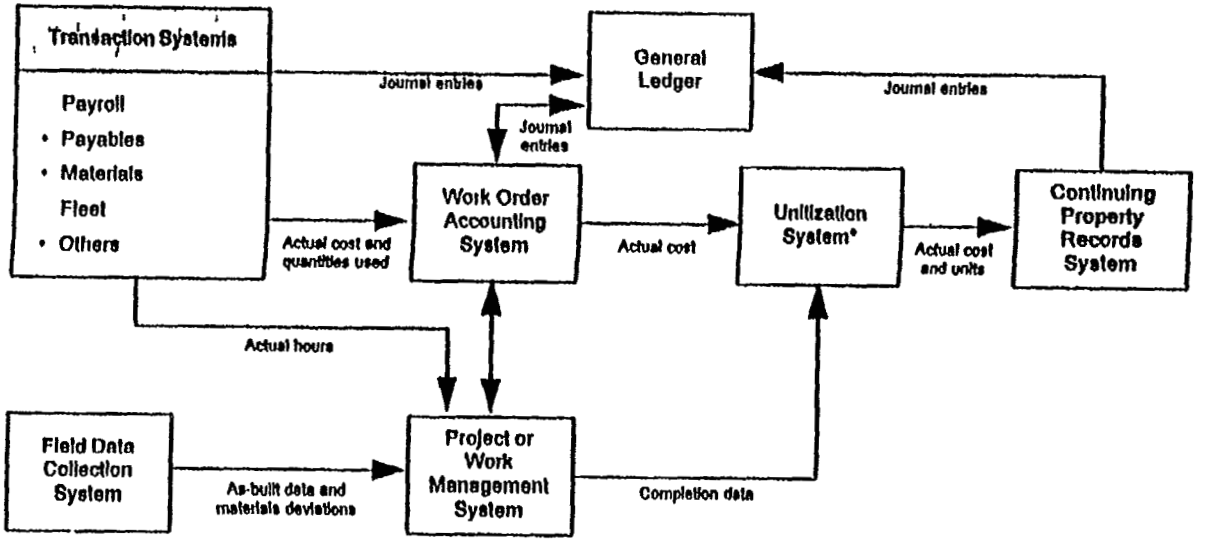
Project Management

- Projects Other Than Major Construction
  - Management System Function
  - Job Initiation
  - Estimating
  - Scheduling
  - Job Control
  - Job Closing

Project Management

- Flow of Data for Project Cost Management and Close Out
  - Important
  - Complicated
  - Affects Many Areas
  - Critical to Accurate Accounting

Flow of Data for Project Cost Management and Close-Out



** May be a part of Continuing Property Records System or Work Management System*

Figure 16-6

BEST MANAGEMENT PRACTICES

BEST MANAGEMENT PRACTICES

- What Are Best Management Practices
- How Do You Evaluate Them
- How To Calculate Savings
- Putting BMPs into Practice

BEST MANAGEMENT PRACTICES

- What Are Best Management Practices
  - Established Methods of Activity
  - New Technologies
  - Old Technologies

BEST MANAGEMENT PRACTICES

- How Do You Evaluate Them
  - Collect Information on Various Methods
  - Calculate Costs on a Unitized Basis
  - Determine Whether Acceptable to You
  - Evaluate Cost Savings Vs. Benefit

BEST MANAGEMENT PRACTICES

- How To Calculate Savings
  - Organize Sample Data
  - Compare to Your Own Data
  - Simple Calculation

BEST MANAGEMENT PRACTICES

- Putting BMPs into Practice
  - YOU Must Decide If BMP Is Acceptable to Your Organization
  - Are There Other Factors That Were Not Considered

BEST MANAGEMENT PRACTICES

- TWO EXAMPLES
  - Overhead Conductor
  - Consumer Accounting & Services

IV - CONSUMER ACCOUNTING & SERVICES

SCOPE OF CASHFLOW

- The 39 EMCs manage approximately $38 million in expenditures related to customer accounting/customer services and information Typical activities in this total include meter reading, answering customer telephone calls, handling customer bill payments, and managing customer records Data was available for 35 of the 39 EMCs The EMCs' total customer accounting/customer service expenditures totaled $37 2 million

METHODOLOGY TO DETERMINE SAVINGS

- Two basic methodologies were utilized, yielding similar results Customer accounting and customer service expenses were broken down to a per mWhr sold basis and a per customer basis These unit costs were compared with both work practices and various structural factors to determine the impact of individual attributes
  - The review of work practices indicated that a number of individual practices correlate strongly with the level of customer accounting and customer service expenses on both a megawatt hour basis and per customer basis
  - There are some structural factors, namely size and average consumption, which have an impact on costs
- To analyze the impact of work/management practices, the impacts of size and consumption were removed from the cost structure, isolating operational factors
- Savings primarily come from two areas
  - Improving the level of practices reduces the unit costs of this function
  - Increasing the size of the EMC also works to reduce the unit cost of this function Based on graphical analysis, the minimum optimal size is approximately 50,000 to 60,000 customers

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WORK PRACTICES THAT IMPACT CUSTOMER ACCOUNTING AND CUSTOMER SERVICE EXPENSES

Practices That Decrease Costs

- Utilizing documented policies and procedures covering the majority of primary activities in the customer accounting/customer service function

- Having documented service standards for the major activities in customer accounting/customer service

- Utilizing hand-held meter reading devices This has a benefit not only for meter reading, but also for billing and customer accounting Related to this is the frequency of re-routing or restructuring of meter reading routes

- Monitoring and tracking of customer traffic and workload in the business offices

- One major group of work practices related to customer telephone answering activities Overall, the better managed the customer contact function, the lower the cost Key work practices/processes supporting this include

  - Monitoring of call volumes

  - Setting goals and objectives for abandoned calls, waiting time, and average talk time

  - Utilizing an automatic call distributor with a manpower planning capability to match staffing with workload and desired service levels

  - Answering calls on an EMC-wide basis as opposed to on a local office by local office basis This offers advantages in economies of scale

Other Common Work Practices Among Low Cost Producers

- Spans of control of seven or more for customer accounting related activities

- Reading inactive meters on a regular basis

- Determining staffing levels based on formal staffing analyses as opposed to using either subjective or historic staffing methodologies

- Use of an automated billing system for creation of customer bills

- Business office procedures for the operation of the business offices

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- Use of a customer information system containing customer records, billing, generating customer orders and customer histories, and linked to meter reading

STRUCTURAL FACTORS THAT IMPACT CUSTOMER ACCOUNTING/SERVICE COSTS

- Depending on the methodology used (per megawatt hour or per customer) different structural components have an impact On a per megawatt hour basis, size has a definite advantage The larger the size, the lower the costs

- On a per customer basis, size and average consumption impact costs, but in opposite directions Size is still a benefit The larger the EMC, generally the lower the cost However, the higher the average consumption, the higher the cost

SCOPE OF POTENTIAL SAVINGS

- The analysis of best practices yields a significant benefit in terms of reduced expenses The analysis of expenses on a per megawatt-hour and per customer basis yields surprisingly similar results Overall, the aggregate benefit of utilizing best practices in the areas previously cited presents a benefit of $4 63 million annually

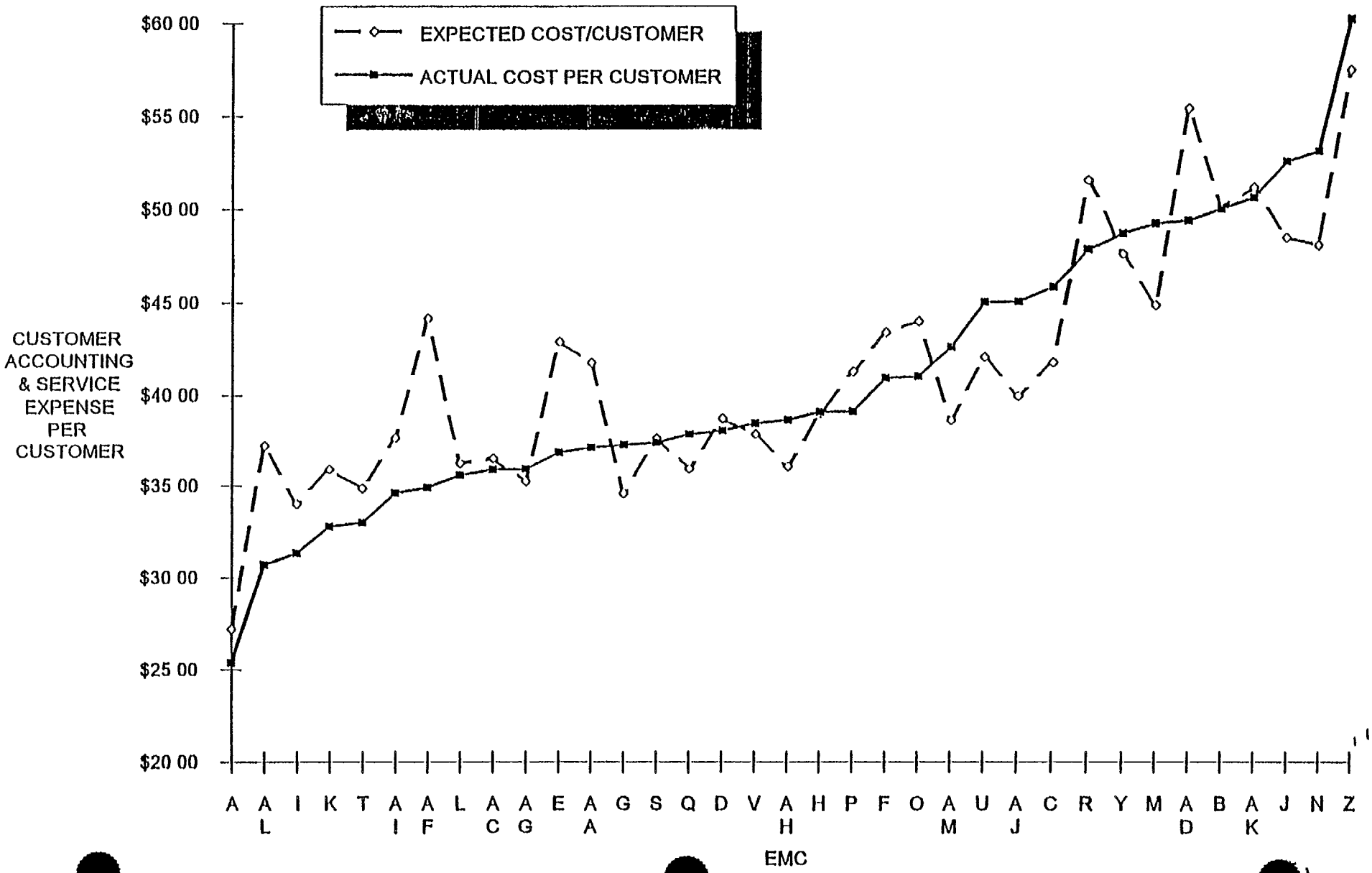
- Increasing the size of the EMC's customer base through some level of consolidation also has a benefit to the EMC Increasing the customer base to approximately 55,000 customers yields an additional aggregate benefit of $2 087 million

- Savings opportunities by implementing best practices are available for 27 of the 35 EMCs for which data is available

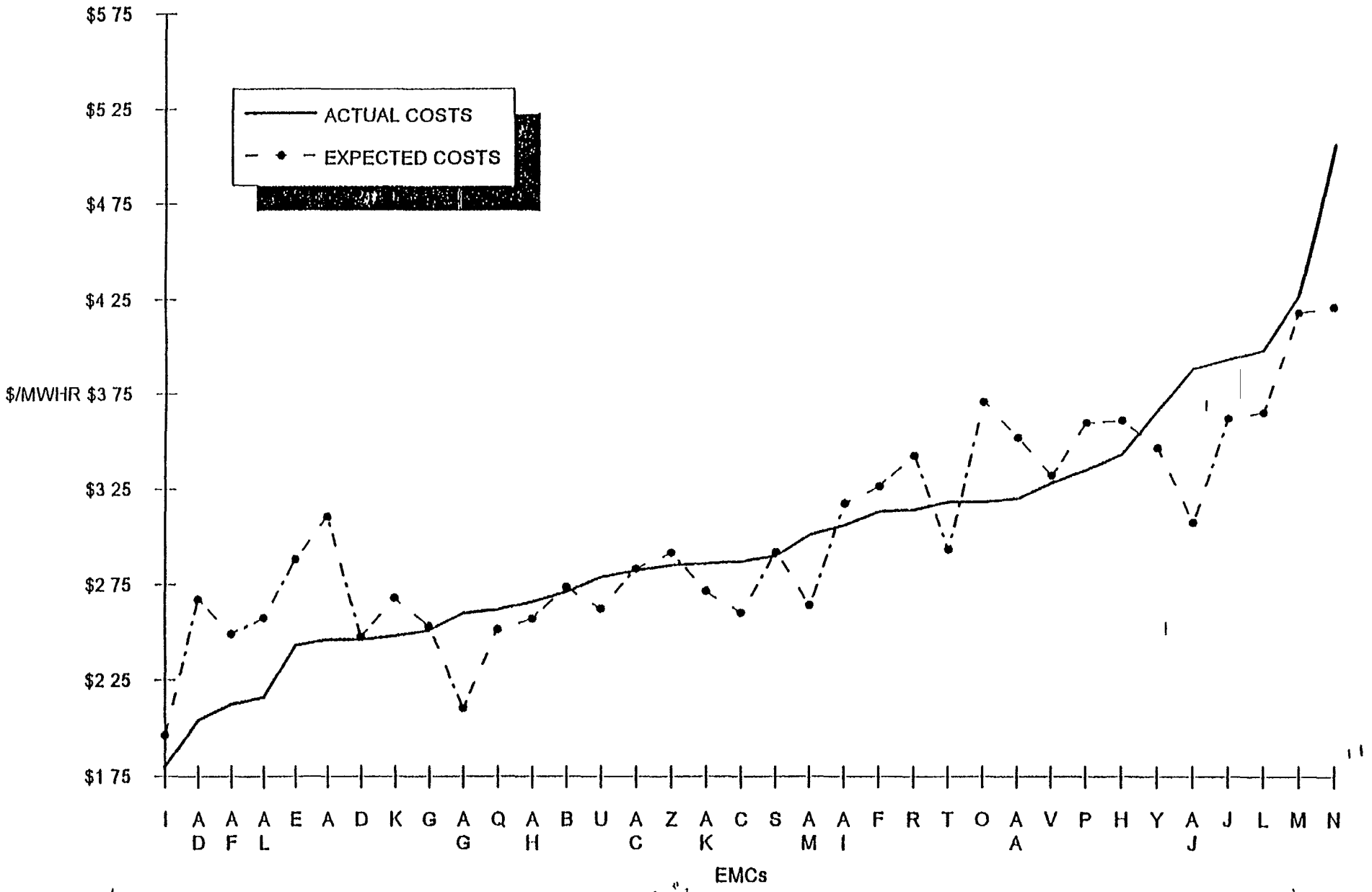
- Savings opportunities through economies of scale are available for 32 of the 35 EMCs for which data is available

- Additional analysis was performed on the specific areas within the realm of customer accounting and customer information and services These areas are meter reading and credit and collections These analyses are documented in section X - Meter Reading and section XI - Credit and Collections Each of these specific areas identified cost savings opportunities To ensure that the impact of best practices are not double counted, the savings opportunities identified in these specific activities were not included in the total savings potential for all areas but are considered to be part of this area

COMPARISON OF ACTUAL AND EXPECTED CUSTOMER ACCOUNTS AND CUSTOMER SERVICE EXPENSES PER CUSTOMER



COMPARISON OF ACTUAL AND EXPECTED CUSTOMER ACCOUNTING AND SERVICE EXPENSES PER MWHR SOLD



II - OVERHEAD CONDUCTOR

SCOPE OF CASH FLOW

- Complete cost and work practices data were available for 34 of the 39 EMCs These EMCs spent $32 2 million to install 2,780 miles of overhead conductor

- EMC costs per mile of installed overhead conductor range from $3,000 to $56,000 The system-wide average cost per mile was $11,500

- The cost of poles, towers, and other items must also be considered part of the activity of installing overhead conductor An additional $28 1 million was spent by the 39 EMCs on installing these items The system-wide average cost per mile to install these other items was $9,650

- In total, approximately $60 million was spent on installing primary overhead conductor

METHODOLOGY TO DETERMINE SAVINGS

- The costs to install overhead conductor were taken from Form 7 (Part E, line 5b - Overhead, Conductors, and Devices (365)) These costs were then analyzed two ways as a total cost and as a unit cost (dollars per mile of line installed) The miles of overhead conductor installed include the new, replacement, and voltage conversion miles as reported in Section 2 of the survey

- The costs were correlated against a wide range of work practices and structural factors to determine the impact of various attributes

  - The review of work practices indicated that a number of individual work practices correlate strongly with costs, on both a total and unit basis Longer-term planning and scheduling, together with formal post-job completion performance analysis evaluations, reduces costs

  - When analyzing total costs, two structural factors, system pole miles and the percentage of system miles that are overhead, were found to impact costs In analyzing unit costs, pole miles helps explain costs best

- To analyze the impact of work/management practices, the components of pole miles and percent underground were removed from the overhead conductor installation cost structure, isolating operational factors Best practices were defined by the EMCs with the lowest work practices cost structures

- Implementing the best practices across all EMCs results in an improvement in cost levels

COMMON WORK PRACTICES

- Implementation of construction standards, specifically, technical materials specifications, bills of materials, and defined installation standards

- Performing a preconstruction walk-down

- Using inspectors part-time for contracted work.

- Pre-staging the materials at the warehouse

- Performing staking services prior to the start of the job

WORK PRACTICES THAT REDUCED COSTS

- Long-term planning and scheduling, especially when combined with monthly and weekly scheduling EMCs that rely on just short term (weekly and daily) scheduling have higher costs

- In analyzing unit costs, a structured work management program (job labor standards, performance reporting, management reports, etc) creates an efficient and effective framework maximizing work crews, and results in lower unit costs

- Because this activity is one of the EMCs' largest expenses, performance evaluation plays a vital role in controlling costs The EMCs that study labor productivity and dollar variances have lower unit costs

- When comparing unit costs, the low cost EMCs traded manpower for equipment to reduce their costs These EMCs utilized smaller crews and more equipment than higher cost EMCs

WORK PRACTICES THAT INCREASED COSTS

- The use of resource loaded schedules for planning and scheduling

- Two common and necessary work practices add to costs assigning a project manager and using a part-time inspector for contracted work Both practices are beneficial but contribute to total costs and must be considered to be an overhead expense

STRUCTURAL FACTORS THAT IMPACT COSTS

- The size of an EMC is a useful indicator of total cost When analyzing total costs, system pole miles and the percent of system miles that are overhead help explain much of the total costs Obviously, the larger the EMC the more they spend on this activity

- However, when analyzing unit costs, installing more overhead conductor resulted in economies of scale and reduced unit costs EMCs that install more have built up the infrastructure and organizational know-how to do so, and leverage this to result in lower costs

- The type of overhead conductor installed (new, replacement, or conversion) did not help explain costs

- Growth rates do not play a factor in determining costs

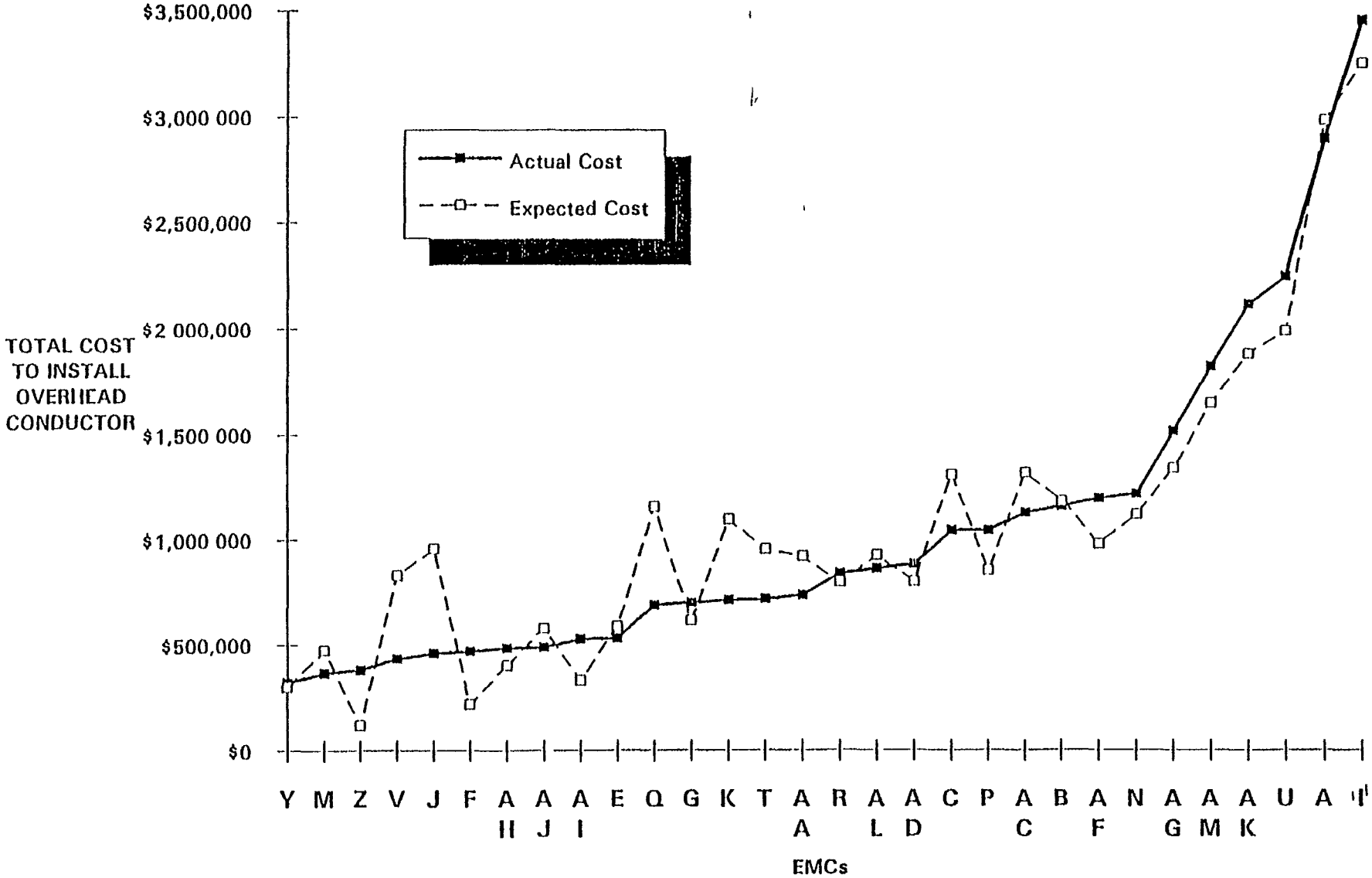
SCOPE OF POTENTIAL SAVINGS

- Analysis of the existing level of work practices versus best practices highlights savings of about 12% of the total cost to install overhead conductor These savings were estimated by applying the work practices of the low cost EMCs to all EMCs The impact is not the same for each EMC Of the 34 EMCs analyzed, 23 showed potential savings ranging from 8% to 21%

- The savings from implementing better practices for overhead conductor installation are projected to be $4 1 million

- Savings opportunities from implementing best practices when installing the other items with overhead conductor (poles, towers, etc) were not directly analyzed However, it is estimated that a similar percentage of costs could be saved This would yield another $3 126 million in annual savings

COMPARISON OF ACTUAL AND EXPECTED OVERHEAD CONDUCTOR INSTALLATION EXPENDITURES



PROJECT

BENCHMARKING

Performance Measurement

PERFORMANCE MEASUREMENT

- Important For Several Reasons
  - Regulatory Agencies
  - Consumer Interest Groups
  - Board of Directors
  - Performance Appraisals

PERFORMANCE MEASUREMENT

- Regulatory Agencies
  - Will Demand Proof of Efficiency for Rates
  - Financing of Construction Activity
  - Good Faith

PERFORMANCE MEASUREMENT

- Consumer Interest Groups
  - Proof of Efficiency is Publicly Available
  - Support For Rates
  - Customers Are Watching You During Construction Activities

PERFORMANCE MEASUREMENT

- Board of Directors
  - Comfort With Existing Management Tools
  - Day to Day Operations of The Company
  - Efficiency of Operations
  - Justifications for Equipment

PERFORMANCE MEASUREMENT

- Performance Appraisals
  - May Be Used For Individuals or groups
  - Effective for Productive Work Force
  - Also Effective For Time Management
  - And Scheduling

PERFORMANCE MEASUREMENT

- Two Excellent Tools
  - Unit Cost Reporting
  - Productivity Reporting

UNIT COST REPORTING

- Development of Costs Based on Specific Units of Activity Performed
- May Include Labor and Material
- Allows for Comparison to Contractor Labor
- Aids in Contract Preparation And Contractor Productivity

Unit Cost Reporting Factors To Consider

- Development of Specific Units or Assemblies
- Determine the Volume of Construction
  - Low
  - Medium
  - High
- Determine a Sufficient Number of Samples To Record

Unit Cost Reporting Factors To Consider

- Make Sufficient Notes to Record Data About Conditions of <u>Every</u> Observation
- Make Sure The Crews Are Comfortable With The Process

Unit Cost Reporting Results

- Insure That The Results Are Statistically Sound
- Develop Tolerances Both + and -
- Discuss The Results With Crew Management To Assure That They Are Comfortable and Understand Process

Unit Cost Reporting Evaluations

- Compare Completed Jobs With Unitized Data
- Look For Jobs Above and Below Set Tolerances
- Ask Questions About The Specific Jobs
- There Are Always Exceptions

	Account/ Code	Record Unit Description	Group Var	Volume Const.	Req. Obs.	Obs. to Date	NOTES
1	364-1	Anchor/Guy Assy	2	HIGH	25	22	OK, skewed rt a bit
2	364-2	Crossarm	4	HIGH	35	5	
3	364,373	Poles 25'-30' Metal & bronze	5	LOW	8	6	
4	364-3	40 & under	2	MED	17	23	Large std dev major outliers
5	364-3	45' & Over	3	HIGH	25	9	
6	364-4	Platform, transformer or regulator	7	< 5	3		
7	364-5	Cluster mount, transformer	5	MED	17		
8	364-6	Cluster mount, equipment	5	MED	17	4	
9	365-1 368	Lightning arrester	1	HIGH	20	31	OK looks good
10	365-2,368	Cutout	1	HIGH	20	33	OK looks good
11	365-3	Oil circuit recloser 1-phase	2	LOW	7		
12	365-3	Oil circuit recloser 3-phase	1	< 5	3		
13	365-4	Ground	1	HIGH	25	20	Looking good
14	365-5	Insulator string	1	HIGH	25	10	Large std dev 2 major outliers
15	365-6	Conductor 4 - 4/0 ACSR per foot	1	MED	17	7	
16	365-6	4/0 & Above per foot	3	HIGH	20	1	
17	365 369-2	2 TPX - 4/0 TPX per foot	2	HIGH	20	42	OK, skewed rt a bit
18	365 369-3	4/0 QPX per foot	1	MED	17	1	
19	365-7	Switch, regular bypass and PKR	3	LOW	10		
20	365-9	Switch, loadbreak 3-phase	3	LOW	3	1	
21	365-10	Switch, disconnect	1	HIGH	17		
22	365-11	Switch 400 and 600 amp	3	MED	7		
23	365-12	Switch, in line	3	MED	18	3	
24	365-8	Timbers	7	LOW	2	1	X
25	365-13	Hanger capacitor	2	LOW	3		
26	367-1	Cable 1/0 & 2/0 URD, per foot 3-ph	1	HIGH	30	19	wide dispersion
27	367-1	1000MCM URD per foot 3-ph	3	MED	20	12	wide dispersion skewed rt
28	367-2	Direct Bore		MED	20		
29	367-3	Cable termination	3	HIGH	30	35	bi-modal distribution problems
30	367-4	Concrete pad	3	HIGH	17	2	
31	367-5	Lightning arrester	1	HIGH	30	8	
32	367-6	Junction box, 3 way & 4 way	5	MED	17	1	
33	367-7	Ground	1	HIGH	17	23	OK looks good
34	367-8	Enclosure PMC & PMH	5	LOW	8	1	
35	368-2	Capacitor	3	LOW	3		
36	368-4	Voltage regulator 500kVA Step-down	3	LOW	2	1	
37	368-5	Transformer 1 5kVA - 25kVA Pole Type	2	HIGH	30	20	Looking good so far skewed rt
38	368-6	37 5kVA - 100kVA Pole Type	2	HIGH	30	1	

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SAWNEE E M C - RECORD UNIT TIME STUDY
RECORD UNIT DATA LIST

LOC NO	CODE	TIME	MEN	SIZE	LENGTH	UTIME	CREW	LOC	BY	SHEET
Poles										
64080-2	364-3	17 35	1 00	40		17 35	1	39	MBS	50
314046-1	364-3	12 00	2 00	35		24 00	1	42	MBS	80
322877	364-3	21 00	2 00	35-5		42 00	1	29	MBS	161
314271-1	364-3	22 00	2 00	40		44 00	1	40	MBS	90
31[illegible]292	364-3	34 00	1 50	40		51 00	2	68	MBS	76
315072	364-3	16 00	4 00	35 5		64 00	1	47	DL	142
317540	364-3	37 00	1 83	40 5		67 71	2	48	DL	155
301287-1	364-3	23 00	3 00	35		69 00	1	52	DL	24
312089	364-3	38 00	2 00	40		76 00	2	68	MBS	77
312501	364-3	19 00	4 00	30		76 00	1	63	DL	74
315132	364-3	40 00	2 00	40-5		80 00	1	20	MBS	145
311147	364-3	21 00	4 00	35		84 00	1	16	DL	75
300358-1	364-3	28 00	3 00	35		84 00	1	75	DL	23
317540	364-3	40 00	2 10	40 5		84 00	2	48	DL	154
63992-1	364-3	56 30	1 50	40		84 45	2	98	MBS	43
63796	364-3	52 00	1 80	40 4		93 60	2	23	DL	150
312755-2	364-3	32 00	3 00	35		96 00	1	13	DL	101
312811-2	364-3	33 00	3 00	35		99 00	1	12	DL	100
63858	364-3	30 00	5 00	40		150 00	2	?	DL	103
295338-2	364-3	85 00	1 80	30-5		153 00	2	8	MBS	38
310603-3	364-3	73 00	3 00	40		219 00	1	28	DL	51
317540	364-3	69 00	3 39	40		233.91	2	48	DL	153
297147-2	364-3	101 00	4 00	40		404 00	1	54	DL	53
64460	364-3	34 00	2 30	45 5		78 20	1	14	DL	148
63797	364-3	60 00	1 33	50-3		79 80	2	23	DL	182
63796	364-3	52 00	1 65	55 3		85 80	2	23	DL	149
63796	364-3	50 00	2 36	45-3		118 00	2	23	DL	180
63797	364-3	51 00	2 55	50 3		130 05	1	23	DL	181
310603-2	364-3	45 00	3 00	45		135 00	1	28	DL	52
63317-43	364-3	71 50	2 00	45		143 00	2	77	MBS	4
63796	364-3	65 00	2 67	45-3		173 55	2	23	DL	151
63796	364-3	58 00	3 00	45 3		174 00	2	23	DL	152

COUNT	23	
RANGE	386 65	
80*RANGE	309 32	
MODE	84	
MEDIAN	84	
MEAN	104 174782	
STD DEV	82 5791990	
Z SCORE =	1 28	= 80% OF RA
CHECK	209 876157	
FREQ DIST		
COUNT	9	

Used plastic pads to save yard — very wet.

SAWNEE E M. C - RECORD UNIT TIME STUDY
RECORD UNIT DATA LIST

LOC NO	CODE	TIME	MEN	SIZE	LENGTH	UTIME	CREW	LOC	BY	SHEET
Anchor/Guys										
64646	364-1	10 00	1 83			18 30	1	75	MBS	168
64646	364-1	10 00	1 83			18 30	1	75	MBS	168
315132	364-1	13 00	1 50			19 50	1	20	MBS	145
64646	364-1	12 00	1 83			21 96	1	75	MBS	168
310603-2	364-1	13 00	2 00			26 00	1	28	DL	52
64475	364-1	14 00	2 00			28 00	1	65	MBS	73
64080 2	364-1	15 22	2 00			30 44	1	39	MBS	50
64475	364-1	18 00	2 00			36 00	1	65	MBS	71
310603-3	364-1	18 00	2 00			36 00	1	28	DL	51
312349	364-1	20 55	2 00			41 10	1	41	MBS	49
317540	364-1	26 00	2 07			53 82	2	48	DL	155
317540	364-1	27 00	2 19			59 13	2	48	DL	153
63858	364-1	33 00	2 00			66 00	2	?	DL	102
397147-2	364-1	24 00	3 00			72 00	1	54	DL	53
317540	364-1	36 00	2 33			83 88	2	48	DL	154
301158	364-1	31 00	3 00			93 00	1	64	DL	27
63317-28	364-1	33 17	3 00			99 51	2		DL	10
295338-3	364-1	99 75	1 00			99 75	2	8	MBS	38
63797	364-1	57 00	2 00	2 GUYS		114 00	2	23	DL	181
63796	364-1	57 00	2 35	3 GUYS		133 95	2	23	DL	152
63797	364-1	81 00	2 00	2 GUYS		162 00	2	23	DL	182
63795	364-1	59 00	3 00	3 GUYS		177 00	2	23	DL	147

COUNT	22	
RANGE	158 7	
80*RANGE	126 96	
MODE		
MEDIAN	56 475	
MEAN	67 7109090	
STD DEV	46 3763778	
Z SCORE =	1 28	
CHECK	127 072672	= 80% OF RA
FREQ DIST		

Crossarms										
63796	364-2	16 00	1 30			20 80	2	23	DL	150
63796	364 2	34 00	1 61			54 74	2	23	DL	180
63796	364-2	15 00	4 00			60 00	2	23	DL	180
63796	364-2	16 00	4 00			64 00	2	23	DL	180
63858	364-2	26 00	3 75			97 50	2	?	DL	103

COUNT	5

Productivity Reporting

- Benefits
  - Measures How Effective labor Forces Perform
  - Actually Does Not Evaluate Dollars
  - Uses Crew-Hours or Man-Hours Instead
  - Can Be A By-Product of the Unit Cost Study Since An Engineering Time Study Is Conducted

Productivity Reporting Methodology

- Should Also Compare Utilization of Time
- Utilization = (Productive Time / Total Time Reported) X 100 Percent
- Utilization Considers Things Like
  - Drive Time
  - Preparation Time
  - Material Gathering
  - Etc...

Figure 15-8
Productivity Measurement Report
419 Overhead Lines

Current Period Hours						Six Month Moving Average				
No of Units	Actual	Allowed	Actual/ Unit	Perf Ratio	Activity	No of Units	Actual	Allowed	Actual/ Unit	Perf Ratio
100	500	500	0 5	100%	A 1135 Install Underground Residential Service					
10	200	300	2 0	150%	A 1234 Install Distribution Transformers					
10	200	100	2 0	50%	A 4567 Install Vaults					
50	80	80	1 6	100%	A 6580 Inspect Breakers					
	1030	980			Total Hours					
				85%	Labor Utilization					

Figure 15-8

Productivity Reporting Management Decisions

- 4 Day Versus 5 Day Work Weeks
- Weekend Work
- Times and Lengths of Breaks and Lunch
- Show Up Locations
- Start and Stop Times for Daily Work
- ETC

DAY 4

8 00 - 10 00	Customer Information Systems	Mr Billy Ussery
10 00 - 10 15	Break	
10 15 - 11 00	Marketing	Mr Billy Ussery
11 00 - 12 00	Work Management	Mr Billy Ussery
12 00 - 1 00	Lunch	
1 00 - 2 45	Automated Systems	Mr Billy Ussery
2 45 - 3 00	Break	
3 00 - 4 00	Information Technologies – The Internet	Mr Billy Ussery
4 00 - 5 00	Power Marketing	Mr Billy Ussery

CUSTOMER

INFORMATION

Overview of Day 4

Overview of Day 4

- Customer Information
- Marketing
- Work Management
- Automated Systems
- Information Technologies
- Power Marketing

Customer Information

CUSTOMER INFORMATION SYSTEMS

- Cannot Have Too Much Data About the Customer
- Maintain As Much Historical Data As Possible
- Critical for Day to Day Customer Contact

CUSTOMER INFORMATION SYSTEMS

- Examples of Customer Information Systems
  - On-Line Inquiry and Order Entry
  - Meter Reading
  - Billing
  - Accounts Receivable
  - Collection Actions
  - Deposits

CUSTOMER INFORMATION SYSTEMS

- Examples of Customer Information Systems
  - Deposits
  - Revenue Reporting
  - Management Reporting

Examples of CIS

- On-Line Inquiry and Order Entry
  - Applications
  - General Customer Account Information
  - Other Historical Data

Electric Service Acc t
Account no. 94 12 (5 C/C no. 2109850 Status of Account
Bill to no. 94 12 0255 Home Phone
Name Other Phone. (000) 000-0000
Add 2 On Date 6/21/96 On Reading 07523
Add Off Date 0/00/00 Off Reading 00000
City ROSWELL Previous Reading 08548
State GA Zip Code 30076-2527 Average KWH 730
SERV LOC Service

METER INFO Serv Class 01 HOUSE
| Meter Serial 21987713 Billing Cycle: M | County 3 FULTON
| Meter Mult 010 Demand Mult | District 9 WEBB
| Route 460 Seq No 01840 Dials 4 | City 02 ROSWELL
| Page# 80 Grid: D-8 Manuf: | Rate 01 RES 1 PHS
| Meter rm# 2 ey no. 0000 | Class 40
| ERT N . 000000 0 Reading Cycle. M | Substation 19 OLD ALABAMA RD
| Latest Date Meter Tested: 0/00/00 | Circuit 3 Phase A Section 2337

Contract Tax Exempt
Minimum bill $8.25
KVA Alloc/Min $ 00
Type ce: Contract Minimum $.00
F8-Load Manag nt Contract Start. 0/00/00 End
Trans No 1830 Size 50
F1--End Job F Update Address F4--Meter Test Inq. F5--Customer Inq.

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NODDFU
Format RNODEMST

ACCOUNT NO 94120255
STATUS
TRANSFORMER CAPACITY 50
TRANSFORMER NO 1830
SECTION NO 2337
KWH USED 1200
ACTUAL KWH
PHASE A
COUNTY CD 3
MINOR DEVICE 9316
MAJOR DEVICE 9332
Device ID
S/L CODE
UNDERGROUND CODE 1

Sawnee EMC — Service Application

NAME
ADDRESS 1
ADDRESS 2
CITY & STATE
ACCOUNT NO
OWNER'S NAME
SERVICE LOCATION OLD ALABAMA RD
TYPE OF SERVICE METER CHANGE
FORMER OCCUPANT

MASTER ACCOUNT NO
PAGE 181 GRID A-7
TAX EXEMPT? Y ☐ N ☐

SOCIAL SECURITY
HOME PHONE
BUSINESS PHONE
ZIP CODE 30349-5520
MEMBERSHIP NO 2036050
ORDER TAKEN BY FAIL

CHARGES PAID
☐ Y ☐ N MEMBERSHIP FEE? $
☐ Y ☐ N SERVICE CHARGE?
☐ Y ☐ N DEPOSIT?
☐ Y ☐ N BALANCE FROM PRIOR ACCOUNTS?
☐ Y ☐ N OTHER CHARGES?

INCP
SWITCH CONSENT ☐ Y ☐ N
BILL TO NO
DATE TAKEN 7/22/97
TIME TAKEN 3:40:41
SOURCE
TICKET NO 354299

ENGINEERING

IF NEW SERVICE ANSWER QUESTIONS
CUT IN COMPLETE? ☐ Y ☐ N
IS COUNTY INSPECTION REQ? ☐ Y ☐ N
HAS APPLICANT NOTIFIED CO ☐ Y ☐ N
RIGHT-OF WAY BEEN SIGNED ☐ Y ☐ N
RIGHT-OF WAY OF OTHERS? ☐ Y ☐ N
IF YES GIVE NAME AND ADDRE-

ELECTRICAL EQUIP
ELECTRICAL HEAT? ☐ Y ☐ N
HEAT PUMP? ☐ Y
AIR CONDITIONER? ☐ Y

SUB DIVISION
BUILDER
DIRECTIONS
LOT #
METER LOCATION FD 20 10520 OLD ALABAMA

WILL CALL WHEN READY? ☐ Y ☐ N
PANEL SIZE
SERVICE CLASSIFICATION CODE
DESCRIPTION
CONTRACT REQUIRED?
TYPE SERVICE OH ☐ UG ☐
WORK ORDER NO
ENGINEER'S NAME
SERVICE DESCRIPTION
LEFT ACCOUNT NUMBER - -
RIGHT ACCOUNT NUMBER - -
SECTION PHASE
TRANSFORMER NO

CONT MIN BILL
BASE CHARGE
SUBSTATION
CITY CODE
RATE CODE
CLASS CODE
KVA ALLOCATION
TRANS KVA
AVG KWH
S/L KWH

740-C CODE NEW LINE 100
REA 219 CODE NEW CONST
SEMC CODE

SECONDARY VOLTAGE	TYPE OF SERVICE 1Ø	3Ø
120/208		
120/240		
240/480		
277/480		

CONSTRUCTION OR SERVICE

METER SERIAL 39852112
METER MULT X 300
METER AMP 25 / FORM# 95
CYCLE 3
READING RTE. 474
SEQUENCE NO 770
ON READING 0 0
DATE TO DO 7 /97

TEMP/PE COMPLETED ☐ Y ☐ N DATE BY
RUN COMPLETED ☐ Y ☐ N DATE BY
METER CHANGE ☐ Y ☐ N
S PERMIT OKAY ☐ Y ☐ N PERMIT NUMBER

DEMAND METER? ☑ Y ☐ N
DEMAND MULT X 300
DEMAND SCALE 0-999
VOLTS 120
ON DATE 7/22/97
WORKED BY MMARC

COUNTY
DISTRICT
MFG LGE
WIRE 4
METER TYPE R4S3
NO DIALS 5

STAKING INFORMATION

X	TYPE OF SERVICE	TRENCH TYPE URD-NT	SERVICE NO SPAN SIZE	METER
	TEMP UG			
	RUN UNDERGROUND			

DISCONNECTS

NAME NEOGEN CO-GA
ACCOUNT NO 05-36-01 OF TAKEN BY
FORWARD ADDRESS
FORWARD ADDRESS 2
FORWARD CITY & STATE
FORWARD ZIP CODE
CHARGES APPLIED
MEMBERSHIP FEE? ☐ Y ☐ N
DEPOSIT? ☐ Y ☐ N
REQUESTED BY FAIL
SERVICE CLASSIFICATION 19 RETAIL 3401 LS

DATE TO-DO 00/00
DATE TAKEN 7/22/97
OFF DATE 7/22/97
OFF METER READING 01370
OFF DEMAND READING 39 32
WORKED BY MMARC
SERIAL NO 2036284
REASON MOVING ☐ METER TEST
NON PAYMENT ☐ REQUESTED
NEW PARTY IN PLACE
MULTIPLIER

REMARKS PLEASE SET METER TO FAIL DATED

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Examples of CIS

- Meter Reading
  - On Reading
  - Off Reading
  - Special Instructions
  - Location
  - Warnings
  - Route
  - Sequence

Examples of CIS

- Billing
  - Historical Billing Data
  - Bad Checks
  - Times Late
  - Times Disconnected
  - Service Charges

Customer Service
1 Account Status 2 Billing History 3 Transaction Hist 4 Rate Specific
5 Mtr Reading Hist 6 Check Payment 7 Note Pad 8 Billing Comparision
Account No C/C No
Display Selection

Status Billing Cycle M Current Due $1 46-
On Date 6/21/96 On Reading 07523 Over 30
Off Date 0/00/00 Off Reading 00000 Over 60
Times Latest Date Over 90
Return Checks 000 0/00/00 Service Chg
Field Collected 000 0/00/00
Delinquent Notice 002 4/07/97
No Late Penalty 00 0/00/00 Project share Amt

Enter a "9" to Display Collection History Total Charges $1 46-

Meter Location
F11 Update Return Checks
F3 Exit F5 Promise Screen F10 Update Charges F6 Budget Billing

Examples of CIS

- Accounts Receivable
  - Account Balance
  - Last Payment
  - Cash Postings

Examples of CIS

- Collections Actions
  - Amount Owed
  - Disconnect Date
  - Late Fees
  - Deposits

Examples of CIS

- Deposits
  - Amounts Collected
  - Refund Dates
  - Refund With or Without Interest

Examples of CIS

- Revenue Reporting
  - Customer Classes
    - Residential
    - Commercial
    - Governmental
  - Rate Classes
  - County
  - City

Examples of CIS

- Management Reporting
  - Aged Accounts
  - Billing Adjustments
  - Meter Reader Performance
  - Disconnects
  - Daily Work Schedules
  - ETC, ETC, ETC

Customer Information Systems Summary

- A Necessary Evil
- Significant Computer Resources Are Required To Maintain Sufficient Data
- With Computer Systems Problems Are Inevitable
- Don't Cut Corners Here
- Make Available To As Many As Possible

MARKETING

MARKETING

MARKETING

- General (Company)
- Residential
- Commercial
- Large Commercial

MARKETING

- General
  - Decide What You Want Your Company To Be Known For
  - Have A Presence In The Community
  - Participate In Community Functions
  - Sponsor Community Affairs
- You Will Be Noticed If You Do Not
- Remember, Your Customers Come In Contact With You Every Month

MARKETING

- YOUR CUSTOMERS PAY YOU MONEY EVERY MONTH, THEY EXPECT TO SEE SOME PUBLIC GOOD IN RETURN

» ME

Marketing
Residential

- Promote Use of Electric Appliances
- Promote Energy Efficiency
  - Insulation Calculations
  - Heat Loss Heat Gain Calculations
  - Thermostat Control
  - Water Heater Control
- Load Management

Marketing
Residential

- Billing Complaints
- Energy Usage Questions
- New Home Inspections and Construction Techniques

Marketing
Commercial

- Very Similar to Residential Except On A Larger Scale
- Generally These Customers Pay More So They Expect More

Marketing
Large Commercial

- These Customers May Have a Choice Of Supplier
- Must Have Favorable Rates and Other Services For Their Consideration
- Their Needs Are On a Much Larger Scale
- Many Times They Have Staff That Are Electrically Educated

Marketing
Large Commercial

- Important To Have Marketing Staff With Engineering Background

Marketing
Other Functions

- Load Management
- Lightning Protection
- Internet Services
- Newsletters
- Annual Reports
- Incentive Rate Options
- Lighting
- Carbon Monoxide Detection
- UPS Services
- Home Warranties
- Infrared Scanning Services
- Independent Consultant Reviews

WORK MANAGEMENT

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WORK MANAGEMENT

WORK MANAGEMENT

- Ties Into Customer Information Systems
- Can Be Beneficial To Customer Service, Engineering and Construction
- Must Be Used Correctly
- Must Be Maintained Accurately
- Can Also Be Used As A Productivity Tool
- Also Performance Measurement

WORK MANAGEMENT

- Must Be Departmentalized
- Dates and Other Information Must Be Maintained
- Project Coding Is Important
- Projected Completion Dates
- Notes, Notes, Notes
- Charges

SAWNEE ELECTRIC MEMBERSHIP CORPORATION

LIST OF VALID SERVICE CLASS CODE

S/C CODE	SEMC CODE	DESCRIPTION	S/C CODE	SEMC CODE	DESCRIPTION
	01	HOUSE *		02	TRAILER *
	03	APART & CONDO *	025	04	CHICKEN HOUSE
	05	PUMP PERSONAL *	021	06	BARN
021	07	HOG PARLOR	024	08	DAIRY
866	09	CHURCH	703	10	TENT
723	11	BEAUTY SHOP	724	12	BARBER SHOP
243	13	CABINET SHOP		14	GARAGE PERSONAL*
799	15	CLUBHOUSE	703	16	CAMP SITES-INDIVIDUAL
	17	BT HSE/DCK-PERSONAL *	651	18	RETAIL SHOP LG
554	19	SERVICE STATION	581	20	RESTAURANTS
783	21	THEATER	799	22	BALL PARK
	23	POOL PERSONAL *		24	TENNIS COURTS-PERSONAL *
738	25	FIRE STATION	483	26	RADIO STATION
018	27	GREEN HOUSE-PERSONAL	201	28	SLAUGHTER HOUSE
821	29	SCHOOLS	399	30	FACTORIES
	31	OFFICES	422	32	WAREHOUSE
025	33	HATCHERY - POULTRY	204	34	FEED MILLS
025	35	EGG GD & PK HOUSE		36	UTILITY METER
	37	OTHER		38	TRAFFIC SIGNAL/FLA
	39	NO METERS	651	40	RETAIL SHOP SMALL
	41	CONSTRUCTION CO TRA		42	SHOP - PERSONAL *
554	43	LODGE		44	SIGNS/ENTRANCE LTS
	45	HOUSE METER	651	46	SHOP COMMERCIAL
799	47	POOL COMMUNITY	753	48	GARAGE COMMERCIAL
494	49	PUMP COMMUNITY		50	SL 100 W HPS OH
	51	SL 175 W MV OH		52	SL 150 W HPS OH
	53	SL 400 W MV OH		54	SL 400 W HPS OH
	55	SL 100 W HPS UG		56	SL 175 W MV UG
	57	SL 150 W HPS UG		58	SL 400 W MV UG
	59	SL 400 W HPS UG		60	SL 250 W HPS UG
	61	SL 250 W HPS OH	551	62	AUTO SALES/SERV
484	63	CABLE TV	493	64	UTILITY COMPANY
651	65	BANKS	431	66	POST OFFICE
799	67	REST AREA	483	68	RADIO TOWER
835	69	NURSERY SCHOOL	242	70	SAWMILL
754	71	CAR WASH	422	72	STORAGE BLDG
721	73	DRY CLRS/LNDRY	799	74	BATH HOUSE
591	75	DRUG STORE	592	76	BEVERAGE SHOP
074	77	ANIMAL CARE/KEN	497	78	IRRIGATION SYS
799	79	RECREATION CENT	543	80	FRUIT STAND
	81	SL-400 W HPS FLD		82	SL - OWN USE
018	83	GREEN HOUSE COM		84	175 W MET H UG
	85	250 W MET H UG		86	400 W MET H UG
	87	1000 W MET H UG	481	88	TELEPHONE CO SR
492	89	NATURAL GAS SER	799	90	BT HSE/DCK - COMM
805	91	NURSING HOME		92	CONSUMER OWNED S/L
	93	RES-LTS/GTE/FEN	799	94	TENNIS COURTS - COMMERCIAL
	95	CAMP SITE - COMMERCIAL		96	HOTEL/MOTEL
	97	SL 100 W MET H UG			

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Date Created February 12 1993
Date Revised October 15 , 1996

CODES FOR JOBS LISTED IN ORDER TRACKING

OBJECTIVE TO DESCRIBE PROJECTS IN ORDER TRACKING WITH THE USE OF THREE SETS OF CODES

CODE (1) THE FIRST SET OF CODES DESCRIBES THE TYPE CONSTRUCTION REQUIRED THE APPLICABLE CODES TO BE USED HERE ARE AS FOLLOWS

FIRST DIGIT	CONSTRUCTION TYPE
1	TEMP SERVICE - U G
2.	TEMP SERVICE - O.H.
3	O.H. SERVICE - WITHOUT A TRANSFORMER
4 ✓	O H. PRIMARY AND SERVICE
5. ✓	SECURITY LIGHT - NO POLE
6 ✓	U G SERVICE ONLY
7 ✓	U G PRIMARY AND SERVICE
8 ✓	SECURITY LIGHT WITH POLE (Normal)
9	REGULATORS
10	CAPACITORS
11	LOAD BREAK SWITCHES
12.	SECTIONALIZING DEVICES
13	RETIREMENT ONLY
14	RECONNECTS - PERMANENT
15	DISCONNECTS
16	(OPEN)
17	OTHER
18 ✓	PERMANENT ONLY
19	ENERGY AUDIT TICKET
20	BILL INVESTIGATION
21	REBATE PROGRAMS
22	DEVELOPER/BUILDER - MEETING
23	LOAD CALCULATION-SIZING OF HTG/COOLING SYSTEM
24	LOAD MANAGEMENT
25	ADVERTISING
26	METER CHANGE
27	TRANSFORMER CHANGE OUT PROGRAM
28	RECONNECT - TEMPORARY
29	SECTIONALIZE DEVICES - FOR SQUIRRELS
30 ✓	SUBDIVISIONS
31 ✓	MULTI-PHASE PROJECTS
32	METER TREATER -- SURGE SUPPRESSER - METER BASE ADAPTER - INSTALL
33	LOCATE -- OUTAGE NOTIFICATION MODULE
34	CARBON MONOXIDE DETECTOR
35	GEORGIA MAGAZINE SUBSCRIPTION
36	METER TREATER - SURGE SUPPRESSER - PLUG-IN ADAPTERS
37	METER TREATER - SURGE SUPPRESSER - METER BASE ADAPTER -- REMOVE
38	CANCEL LOCATE SUBSCRIPTION SERVICE
39	CANCEL GEORGIA MAGAZINE SUBSCRIPTION
40	TROUBLE TICKET - RIGHT-OF-WAY
41	TROUBLE TICKET - STREET LIGHT MAINTENANCE
42.	TROUBLE TICKET - VERIFY METER OR LOT INFORMATION
43	TROUBLE TICKET - METER REPAIR/MAINTENANCE/INSPECTION
44	TROUBLE TICKET - TURN POWER ON NON-PAY
45	TROUBLE TICKET - LANDSCAPE REPAIR
46	TROUBLE TICKET - SERVICE CHANGE
47	TROUBLE TICKET - STEALING POWER
48	TROUBLE TICKET - LINE MAINTENANCE
49	TROUBLE TICKET - LINE DOWN/LOW CLEARANCE

(Continued)

CODES FOR JOBS LISTED IN ORDER TRACKING
(Continued)

CODE (1) (Cont'd) THE FIRST SET OF CODES DESCRIBES THE TYPE CONSTRUCTION REQUIRED THE APPLICABLE CODES TO BE USED HERE ARE AS FOLLOWS

50.	TROUBLE TICKET - CUT UNDERGROUND CABLE
51	TROUBLE TICKET - REQUEST TO MEET WITH ENGINEER
52	TROUBLE TICKET - CHECK VOLTAGE
53	TROUBLE TICKET - LOAD MANAGEMENT MAINTENANCE
54	TROUBLE TICKET - DISCONNECT SERVICE FOR REPAIR
55	TROUBLE TICKET - OTHER
56	ENERGY AUDIT - PENDING SCHEDULING
57	BILL INVESTIGATION - PENDING SCHEDULING
58	BANK/CREDIT CARD DRAFT REQUEST FOR INFORMATION
59	READ METER
~~60.~~	~~TEMP. TO PERM.~~
61	Pending Street light request (subdivision U6)
62	System Improvement / Work PLAN item

CODES FOR JOBS LISTED IN ORDER TRACKING
(Continued)

CODE (2) THE SECOND SET OF CODES DESCRIBES THE LOCATION OF APPLICABLE CODES TO BE USED HERE AS FOLLOWS

SECOND DIGIT	DEPARTMENT SECTION
1	ENGINEERING SECTION
2	CUSTOMER SERVICE
3	SERVICE
4	DRAFTING
5	CONTRACTOR
6	CONSTRUCTION SECTION
7	WAREHOUSE
8	RIGHT-OF-WAY
9	LOCATE
10	ENERGY SERVICE
11	LOAD MANAGEMENT
12	L/M ASSIGNED TO CONTRACTOR
13	RETIREMENT TICKETS
14	COMPLETED RUN
15	SHIPPING -- DATA PROCESSING
16	ENGINEERING -- SYSTEM PLANNING
17	ACCOUNTS RECEIVABLE
18	HOLD

CODES FOR JOBS LISTED IN ORDER TRACKING
(Continued)

CODE (3) THE THIRD SET OF CODES DESCRIBES THE PROJECT STATUS OR TYPE OF ACTIVITY APPLICABLE CODES TO BE USED AS FOLLOWS

THIRD DIGIT	PROJECT STATUS
1	EMERGENCY
2	CONSUMER
3	WILL CALL WHEN READY
4	HOLD FOR PERMIT
5	JOB BUILT-METER NOT SET
6	NEED RIGHT-OF-WAY EASEMENT
7	NOT READY
8	HOLD-CONSTRUCTION COST
9	UNDERGROUND RUN - METER NOT SET
10	30 DAY LETTER MAILED
11	WORK PLAN ITEM
12.	L/M NEED APPOINTMENT
13	L/M NEED SPECIAL EQUIPMENT
14	SPECIAL PROJECT ALL TYPES
15	CUSTOMER SATISFACTION SURVEY
16	OUT OF STOCK
17	ORDER FILLED AND SHIPPED

(C-S-CODE.DOC)

CODES 06 14 09 ORDER TRACKING - CONST CODE C

MEMB PH # WK PH # Date Applied 01 27 97

NAME COUNTY FORSYTH MSF Y/N DEP Y/N

SV LOC SUB DIV DEERLAKE

SERVICE DESC LT LOT# 0310 Job Reference No 310598 - 1

TYPE SERV COMPLETED RUN UND UG/OH UG BUILDER

DIRECTIONS

TAKEN BY ROBIN

	SCHEDULED DATES	ACTUAL DATES	
1 Assigned to ENGINEERING	1/28/97	1/28/97	Account No 84 20 0258
2 MATERIAL STAGED		0/00/00	Const Cost Paid Y/N
3 ENG RELEASED TO CONTROL	1/31/97	0/00/00	Const Cost 00
4 RELEASE TO CONST FOR SCH	2/03/97	1/28/97	Enter decmial point above
5 SCHEDULED FOR WORK		2/03/97	Service Charges
6 CONST RE-SCHEDULE DATE		0/00/00	Left Account No
7 COMPLETED BY CONSTRUCTION	2/11/97	2/03/97	Right Account No
8 RETURNED TO CONTROL		Work Order No	0310598
9 DATE TO REVIEW		Foreman	KNAPP
10 PLACE IN HOLD	0/00/00		
11 RELEASED FROM HOLD	0/00/00		FOREMAN
12 ORGINAL COMPLETE DATE	0/00/00		MSN 00 000 000 R 00000

Eng Assigned DRAFTING

WIRE SIZE 4/0TPX

FOOTAGE 120

F2 Notes F12 Update Record F3 To Exit HELP - FOR CODES

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Work Management Reporting

- Basic Schedules Should be Developed By Department
  - Engineering 3 Days
  - Processing 1 Day
  - Construction 6 Days
- Daily Reports Should Drive Construction Scheduling
- And Customer Requests

AUTOMATED

SYSTEMS

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AUTOMATED SYSTEMS

Automated Systems

- Meter Reading
- Phone Systems
  - Account Status
  - New Job Status
  - Outage Notification
- Outage Notification
- Staking Data Entry

Automated Systems

- Very Expensive
- Must Evaluate With Conventional Methods
- Cost Versus Benefit
- Communications Is Always A Question

Automated Systems Benefits

- Less Labor
- Less Fringe Benefits
- Fewer "Human" Errors
- Lower Costs (Sometimes)
- Marketability
- Customer Service

Automated Systems Concerns

- Cost
- Maintenance and Upkeep
- Technology Changes
- Support for Problems
- Internal Support Staff

Automated Systems

- YOU NEVER REALLY GET RID OF PROBLEMS - YOU JUST SWAP THEM FOR A DIFFERENT KIND OF PROBLEM

Automated Systems to Consider

- Meter Reading (AMR)
  - Probably Most Widely Studied
  - Benefits include:
    - Accuracy
    - On Demand Readings
    - Less Errors
  - Concerns include:
    - Communications
    - Cost

Automated Systems to Consider

- Phone Systems
  - Obtain Billing Information
  - Account Balance
  - Disconnect Dates
  - New Job Status
  - Outage Notification Systems
  - "ON - HOLD" Messaging

Automated Systems to Consider

- Outage Notification System
  - Scientific Atlanta's LOCATE System
  - Others Are Available

Automated Systems to Consider

- Staking Sheet Data Entry
  - Used By Field Engineers
  - Update Electronic Staking Sheets
  - Automated Download To System

Automated Systems to Consider

- Other Systems
  - With Personal Communications Systems (PCS) Becoming Available, Possibilities Are Endless

Automated Systems to Consider

- Finally
  - Consider Any System Long and Hard Before Making A Commitment
  - Visit Someone Who Has The System In Operation

INFORMATION

TECHNOLOGIES

INFORMATION TECHNOLOGIES

The Internet

The "NET"

- An Endless Source of Information
- Can Be a Wonderful Tool To Communicate With Your Customers
- And Employees
- And The Rest of The World

A Sample of Sawnee's Home Page

WWW.SAWNEE.COM

SAWNEE

Owned by Those We Serve

Sawnee Electric Membership Corporation is a member-owned electric energy provider to an area covering seven north Georgia counties in suburban Atlanta. Our focus is evident in our Customer Care Center especially designed to make your life easier when it comes to energy and energy related products and services We encourage you to learn more About Sawnee using our home page for finding more information

We encourage you to visit us frequently to see who we have featured or what is in our latest newsletter by clicking What's New Who knows, you may find a member that has just what you're looking for in the Power Pages If you have little ones, take a look at Kid's Corner or even the Weather Wise area so you can always stay up to date

Our high growth brings many changes, if you don't see something you would like to know more about, please contact us Because at Sawnee EMC - "We're More Than Just Electricity, We're Service"

Home | *Customer Care Center* | *About Sawnee*
Sawnee Highliner | *Power Pages* | *Kid's Corner*
Weather Watch

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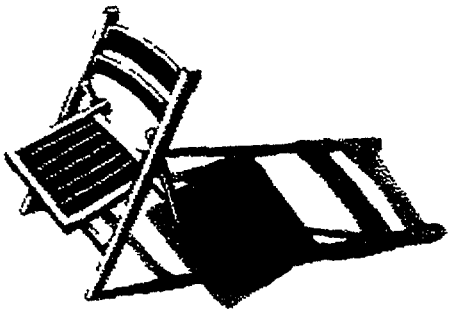
Mission Statement



Sawnee EMC has over 240 employees dedicated to customer service Finding ways to help members reduce their power costs Making bill payment easier And keeping the power on That is our focus because that is how we can make life easier for our customers

Sawnee responds to thousands of customer inquiries every year Sometimes all it takes is a quick answer over the phone about our billing procedures or various other programs Sometimes it means a visit by an Energy Services Representative to do an energy evaluation and give recommendations to improve a home's energy efficiency And sometimes it means sending out our on call outage team to investigate a middle of the night outage during a violent storm But, one thing remains the same with every call - Sawnee EMC responds immediately And by extending our weekday telephone hours from 8 00 am to 9 00 pm, we are able to serve our customers better

We're More Than Just Electricity, We're Service.

OUR MISSION STATEMENT

MISSION	Sawnee Electric Membership Corporation exists to serve the changing needs of members by enhancing the quality of life through active support of community developments and identifying and serving the member's energy needs
VISION	We will achieve our Mission in a manner that members will choose and support us, even when faced with other options
STANDARDS	The standard for the consideration, development and implementation of all corporate activities will be Customer Focused We will be mindful that we exist to serve our customer's needs

Conscientious	We will be conscientious in the quality, cost and equity of the service provided
Competitive	We will strive to be competitive in value, products and services
Financially	We will maintain a reasonable and equitable financial corporation
Competent	We will plan and execute each task in a competent business and professional manner
Credible	We will earn each day, by our acts, the respect of our members and business community
Creative	We will constantly strive to do better at what we undertake
Heritage	We will remember our cooperative's heritage and perform under the best sense of cooperative values and beliefs

Home | *Customer Care Center* | *About Sawnee*
Sawnee Highliner | *Power Pages* | *Kid's Corner*
Weather Watch

Brand New Service
Outdoor lighting
Reconnect Service
Disconnect Service
Builder/Temporary Service
Change Service

Your Energy
Residential FAQ's
Commercial F-
Service Area/L ations
Energy Products & Services
General Information

Hi, my name is Willie Wiredhand and I want to make life easier for you I know moving can be a real headache so I can help you with your Brand New Service When you set yourself up for service, add a some real ni- Outdoor Lighting so you can see what's going on at night If you have a meter you haven't i using, Reconnect Service and if you're moving, Disconnect Service on line Our Builder/Tem y Service allows lders and you to obtain service to construct that w house Occasionally change something eed to know like your telephone number Be e to keep me up to date by updating your int. nation under Change Service

Everybody should investigate Your Energy, it has plenty of tips, can help you with your energy statement, and may even help you earn a few dollars I even have a few pals that can help you with your Residential or Commercial frequently Asked Questions (FAQ's) If you have a few moments, let me show you just what Service Area I can cover in north Georgia Yes, I haven't forgot you might want to know our Locations, here are even few convenient pay stations near you Did you know that I'm made up of wire? It's the same wire at you'll find in our energy products If fact, I have other energy services you probably didn't know I could do I can even provide you some General Information

Home | *Customer Care Center* | *About Sawnee*
Sawnee Highliner | *Pov Pages* | *Kid's Corner*
Weathe atch

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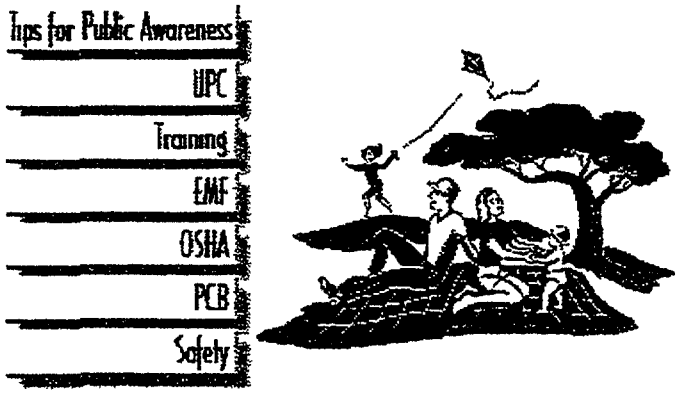

Tips for public awareness

A MATTER OF LIFE AND DEATH

Electricity provides necessities and luxuries that certainly add to the quality of our lives However, carelessness with electricity can unfortunately result in burns, injuries or even death

Similar to lightning, electricity is always striving to find a path to the ground Should any part of your body come in contact directly or indirectly with an energized object, you have provided that pathway to the ground and, therefore, are in immediate danger

Sawnee EMC encourages you to remember the following safety rules

- Consider any electrical lines dangerous Keep all objects (example kites, ladders and antennas) away from power lines
- Do not attempt to raise or move electric lines
- If your utilities are underground, call the Utilities Protcetion Center (UPC) before digging UPC will request that Sawnee and your other utilities mark underground lines Remember, it's the law that you must call UPC before digging!
- Report to Sawnee EMC any potential power line hazards, including trees growing into the lines
- Always stay away from any electric line down on the ground Call Sawnee EMC immediately
- Never touch a person or object that is in contact with a power line

UTILITY PROTECTION CENTER

(Atlanta - 770-623-4344, outside Atlanta 800-282-7411)

The "Utility Protection Center" or UPC takes requests for all utilities with overhead and underground equipment It's a FREE call All you do is give your name, address, type of work, and telephone number, then UPC will contact each utility listed for your area. UPC will also give you a verification number to prove you called in accordance with Georgia Law

Under Georgia Law, each utility has 72 hours (3 days) to locate their facilities The days do not include holidays and weekends Calls after 3 p m EDT will be begin the three day rule the next working day Also remember when working within the vicinity of overhead lines, call the UPC just like calling before you dig

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TRAINING

Sawnee provides continuous training to all employees on a regular basis Training ranges from in-house programs, having a specialists come to train, even have our employees go to statewide programs, and sometimes other electric utilities

EMF

Electro-Magnetic Fields (EMF) have become an increasingly hot topic for discussion Several renowned universities and other institutions have made observations about EMF and their effects on health Magnetic Fields are generated by electrical devices conducting electricity The field strength is dependent upon the amount of electrical current flowing in the device, not the voltage

Most appliances will produce higher reading than powerlines The reason for this is the amount of current and more importantly, the amount of distance from the source Oglethorpe Power Corporation (our power wholesaler) can provide you additional and current information about EMF

OSHA

The Occupational Safety and Health Administration (OSHA) enforces regulations on industry to meet certain guidelines for employee safety Sawnee continually updates our employees on new regulations and work practices through training programs

PCB

Poly-chlorinated biphenyl's or PCB's is a component of old oils used in electrical equipment The United States Navy began using PCB's in transformer oils aboard naval ships PCB's were added to the oils to prevent fires from occurring Later it was discovered that PCB's were toxic to the environment and subsequently were banned in 1972 Since then, no equipment could be manufactured with this element in the oil In spite of the ban, some equipment was manufactured with the residue in clean oil Sawnee takes an active attitude about PCB's and removes any equipment found to have this agent in the oil If you believe there is a piece of equipment leaking, please contact our office immediately Our response team will review the site and take the appropriate action

SAFETY

Sawnee is conscientious about the safety of the public and employees Should you see any employee, truck, or our contract employees creating a hazard to you, the public, or another employee, please report it by telephone at 770-887-2363

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Sawnee Highliner | *Power Pages* | *Kid's Corner*
Weather Watch

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The Sawnee Highliner

Sawnee Electric Membership Corporation

Volume 17, No. 1, 1997

- World-Wide Communications
- Convenience
- Stop the Surge
- Here's Watts Cookin'

Volume 17, No. 2, 1997

- Pole Check-Up!
- Caller Beware
- Cutting Back
- Here's Watts Cookin

Volume 17, No. 3, 1997

- Plan Your Planting
- Electri Tip
- Surf the Web with Mindspring
- Notice of Patronage Capital Credit Assignments for 1996
- Here's Watts Cookin'

January

World-Wide Communication

At Sawnee EMC, communication with the world is just a phone call away We believe that language should never be a barrier when conducting business And how do we do it? By using AT&T Language Line Service

AT&T Language Line Services enable us to communicate with consumers of any nationality Occasionally, language differences makes conversations difficult, but with help from an interpreter, exchanging information can be done in a simple and effective manner whether it's technical information or just setting up electric service

Translators are available 24 hours a day and provide interpretation from English into as many as 140 languages For more information, contact Sawnee's Customer Service Center at 770-887-2363, ext. 7111

Convenience

It just keeps getting easier to pay your bills at Sawnee EMC And we're taking convenience a step further with our new credit card draft program.

This program is designed to enable you to pay your electric bill via your credit card (Master Card, Visa, Discover, American Express, or Band Debit Card) and never have to write a check or come in to our office to pay

You will continue to receive a monthly bill and the message "Your bill will be paid by Credit Card Draft" will be printed on it Under Sawnee's Credit Card Draft Program you pay no fee to use the service and we draft you account on the last possible day

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Stop the Surge

As home electronics and appliances have become more sophisticated, they have also become more sensitive to normal electric occurrences Voltage surges are short periods of high voltage or "spikes" of electricity that occur through power lines, telephones, TV antennas and cable TV lines Even when equipment is turned off, voltage surges can affect home electric equipment.

The best protection is to put a surge suppressor where electricity enters your home, as well as inside your home where equipment is connected

Sawnee offers meter-based suppressors called METER TREATER and plug-in suppressors by Panamax For more information on these products please call our Customer Service Center at 770-887-2362, ext. 111

Here's Watts Cookin'

Peanut Butter Pie

- 8 oz cream cheese
- 1/2 Cup sugar
- 3/4 Cup peanut butter
- 4 oz Cool Whip
- Graham cracker crust

Cream peanut butter, sugar, and cream cheese Fold in 4 oz Cool Whip Pour into graham cracker crust. Chill top with additional Cool Whip before serving Enjoy!

Send us you favorite recipe - If we print it, we'll credit your account $5 00!

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February

Pole Check-Up!

Sawnee EMC annually inspects approximately ten percent (10%) of all of its wood distribution poles Each pole that is to be inspected requires that we dig around the pole to look for signs of decay or deterioration. To extend the useful life of the pole, we treat the poles with EPA approved preservatives which decreases the overall cost and increases the reliability of our distribution system Osmose Pole Inspection Company will be performing this inspection for us beginning March 31, 1997, in the Hwy 9S, Castleberry road, Hwy 369, and Shady Grove Road areas of Forsyth County

If you have questions or need additional information on these inspections, please contact our Customer Service Center at (770) 887-2363, ext. 7-111, or Gary Mauldin, Engineering Services Superintendent, ext. 7-312

Caller Beware

If you receive a page with a number you don't recognize - beware - it could be a scam. There are two dishonest phone scams that could deceive you into calling numbers in the Caribbean with astronomical per minute charges

In both scams, you could receive a page to dial a number in the 809 area code in the Caribbean. When you call the number, you hear a recording that tries to keep you on the line as long as possible, as you receive worthless information. In a similar scam Rich Petillo, an AT&T corporate security manager stated that, "We blocked calls over the AT&T network to a pager scam number in Antigua that was clearly fraudulent."

The suppliers of these recorded messages along with the overseas phone companies can profit greatly, while you end

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up with the bill, so beware

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Cutting Back

Because Sawnee EMC is concerned about safety and providing reliable electric service, we need your support in keeping trees away from power lines If you see trees that need to be trimmed around power lines, or you have any questions regarding tree trimming, please call our Customer Service Center at (770) 887-2362, ext 7111

Here's Watts Cookin'

- 1 Cup sour cream
- 1/2 Cup sugar
- 1 egg
- 2 teaspoons flour
- 1 teaspoon vanilla
- 2 Cups sliced apples

Filling

Beat together sour cream, sugar, flour, salt, egg, and vanilla Add apples and mix thoroughly by hand Pour into an 8" unbaked pie shell and bake at 400F for 25 minutes

Topping

Mix together 1/2 Cup sugar, 1/4 Cup butter, and 1/3 cup flour Sprinkle on top and bake 15-20 minutes more
Thanks to Nita Funk

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March

Plan Your Planting

As spring approaches, we will all begin making the long awaited spring landscaping plans Many times those plans include covering up the area around Sawnee EMC s transformers, junction boxes and switching cubicles with plants and trees Sawnee EMC would like to remind you that planting shrubs and tree within ten (10) feet of these items could cause serious problems as well as a potentially dangerous situation for our personnel.

When an outage occurs and we are in the process of restoring service, shrubs and unnecessary delays Obstructions could also cause potentially hazardous conditions for our crews while operating equipment. Personnel that may be required to perform work on these transformers, etc during extreme weather conditions must be able to work safely and effectively Often we are faced with the only option of removing these landscaping items to be able to perform this work safely

Generally, perennials, annuals and other plants that are low to the ground are not a problem If your plans call for digging around Sawnee EMC s facilities, remember to call Georgia's Utility Protection Center at 1-770-623-4344 before you dig

Digging in Georgia with mechanized equipment requires 72 hours notice so that the various utilities can be located So

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please remember, for your and our crew's safety, please follow these suggestions and may you have happily planting this spring

ELECTRI TIP

On heat pumps, keep all supply vents open. Closing vents could damage your system.

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Members of Sawnee EMC can now surf the web with Mindspring, a leader in internet service providers, at great discounted rates This unique service enables only members of Sawnee EMC to receive one of two (2) available service plans at special rates

PLAN #1 "The Standard" Service

- $13 45 a month for the first twenty hours (normally $14 95)
- $1 00 for each hour over the first 20
- A low $10 00 start-up fee (normally $25 00)
- Includes 5MB of Web/FTP space

Plan #2 "The Works" Service

- $24.25 a month for unlimited use (normally $26 95)
- A low $10 00 start-up fee (normally $25 00)
- Includes 10MB of Web/FTP space

So, if you're ready to surf the web call Sawnee's Customer Service Center at (770) 887-2363, ext. 7111 and save money with membership Also, ask about our other Premium Pay products

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Notice of Patronage Capital Credit Assignments for 1996

Sawnee Electric Membership Corporation is a non-profit organization. Our bylaws require us to set aside, for each member in each operating year, any funds in excess of operating cost and expense in the form of Patronage Capital Credits

The patronage capital is used as equity to reduce the level of debt the Corporation would otherwise be required to assume and is invested in the assets of the Corporation which include poles, transformers and other physical plant items The Corporation's policies currently allow for the retirement of patronage capital on a 20-year rotation cycle, as well as to estates of deceased members

Based on the total capital provided to the Corporation in 1996, our members will receive an allocation based on this total revenue equaling 4 44 percent from Sawnee EMC operations and 1 68 percent from margins that are assigned to us from associated organizations such a s Oglethorpe Power, our wholesale power supplier; NRUCFC, one of our lending institutions; and others

You can calculate your own Patronage Capital Credits by multiplying your total electric bills for 1996 by the factors shown below (See examples below)

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If you have any questions about your patronage capital assignment, please contact Mr Larry Kohn, Manager of Member Services, at (770) 887-2363 or 1-900-635-9131, ext. 7390

Percentage	Assigned by	Total 1996 Bills		
		$500	$750	$1,000
4 4439%	Sawnee EMC	$22 22	$33 33	$44 44
1 6824%	Associated Organizations	$8 41	$12 62	$16 82
6 1263%	Total Assignment	$30 63	$45 95	$61 26

NOTE These calculations are based on normal retirement of patronage Capital and are not applicable for earlier retirement to estates of deceased members back to top

Here's Watts Cookin'

Thanks to Edna Mize

The Best Chicken Casserole

- 4 Chicken breasts cooked and diced
- 1-8 oz carton of sour cream
- 1 Cup Ritz crackers (crumbled fine)
- Can cream of chicken soup
- Stick melted butter

Mix chicken, soup, and sour cream then put in casserole Mix melted butter and cracker crumbs Spread crumb mixture over chicken mixture Bake for 35-40 minutes in oven at 350F

Send us you favorite recipe - If we print it, we'll credit your account $5 00!

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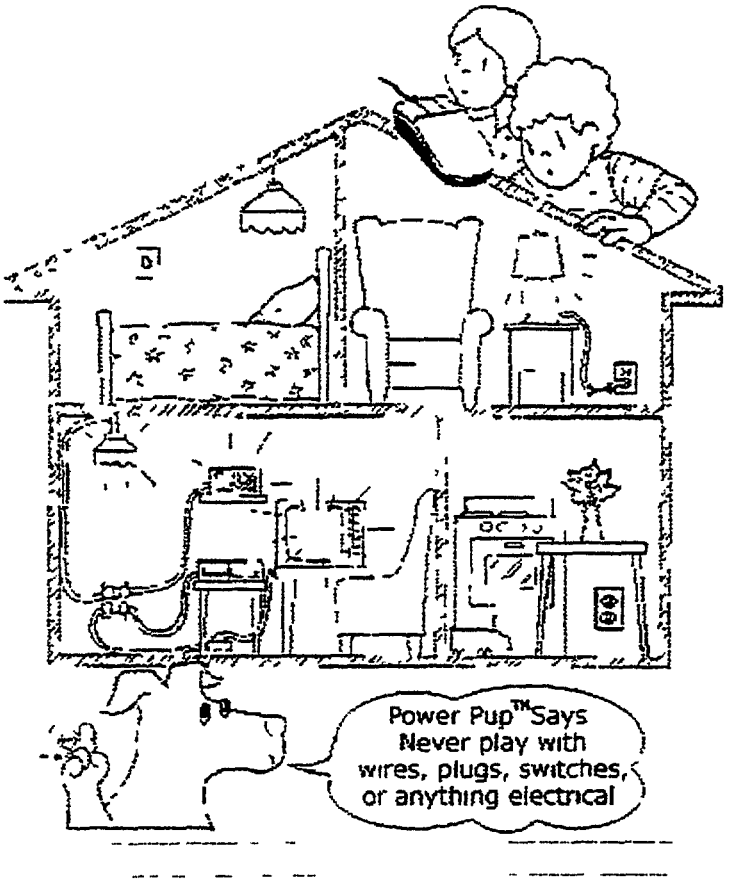
Be Careful In Your House!

Never play with electrical cords and plugs
They can be dangerous.

Click on the 3 electrical hazards in this home that need to be fixed Do you know why they are dangerous?



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NEW SERVICE FORM

Sawnee will make every effort to have your service built when you need it We typically set a maximum of ten (10) working days to construct your service Please let us know if you have special circumstances New members will be billed a $5 00 membership fee on their first energy statement and a deposit of $100 00 (unless we receive a letter of credit from your former electric utility) If you require commercial services, please refer to the Commercial FAQ Please proceed with our on-line "New Service Form" a complete member package will be mailed to you within five (5) working days If you have specific concerns please E-mail us or telephone us

◯ Overhead service (no charge) ◯ Underground service (fees apply)	
Name to place Account in:	
Company Name (If applicable):	
	Federal ID#:
Email	
Billing Address:	Street
	City/State/Zip
Physical Address: **(Actual service location)**	Street
	City/State/Zip
Nearest Account Number (silver tag located on meter)	
Home telephone:	
Work telephone:	
Other telephone:	
Social Security # **or Member Number** **(if you have existing service)**	
Subdivision Name: **(If applicable)**	
Lot Number:	**Type of service:**
Main Breaker Size:	
Primary Heating	◯ **Efficient Electric** Heat ◯ Fossil Fuel (Gas) Heat
A/C Size:	**County:**

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◯ Ready for connection ◯ Not ready ◯ Call when ready	
County notified for inspec n: ◯ YES ◯ NO	Permit Approved: ◯ YES ◯ NO
If not in a subdivision, ha e you signed a Right-of-Way Easement for service?	◯ YES ◯ NO
If we have to cross the property of someone other than you, have they signed a Right-of-Way Easement for you?	◯ Y S ◯ NO ◯ N/A
Request by:	
Directions:	

DISCLAI ER

I understand as the requesting party that I am responsible for this information I acknowledge that sending Sawnee EMC an electronic copy of this form releases Sawnee EMC and its agents from expense(s) and/or damage(s) r ting from incorrect information provided herein I acknowledge that the accuracy and integrity o hese forms reflect the service requested herein I furthermore understand that I will be subject to a deposit unless I have my current electricity provider send a letter of credit for a period of service not less than twelve (12) months

Form Submit Form Reset

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Residential FAQ's

I am moving in to your service area. How do I obtain service?

- You may visit our Headquarters or Branch office in person, you may also complete our on-line new service request form or contact our Customer Care Center by telephone

Are there any deposits when obtaining service?

- If you can provide a letter of credit (with at least 12 months of good service) from your previous electric company, Sawnee will waive the required deposit If no letter of credit is available, there will generally be a deposit of $100 00

Are there any fee(s) when obtaining service?

- The base non-refundable construction fee for temporary service is $40 00 and a $25 00 fee for reconnecting an existing meter Long line extensions and underground service may have other additional fees Request that the field representative for your service identify any additional fees

I am moving How do I transfer my service to another address.

- In our service area, complete a new service or reconnect service for your new address and complete a disconnect service for your former address

How do I change incorrect information you have about me?

- You may telephone our Customer Care Center or do change it on-line

How do I get Sawnee to check my service, trim trees, maintenance or other things?

- You may telephone our Customer Care Center or do work on- line

How do I get information about how to reduce my energy cost?

- You may telephone our Customer Care Center or ask our energy expert (energyexpert@sawnee com)

What other rates are there for my home?

- Sawnee has a few rates You may telephone us or check them out here

Does Sawnee work on equipment inside my home?

- Sawnee maintains and repairs all items up to the meter We recommend seeking a licensed electrician to review any concerns about inside wiring

I have a unique question and need individual help, what do I do?

- You may telephone our Customer Care Center

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The Membership
Advantage

Subscription	Basic
Georgia Magazine	Bank Draft
Meter Treater	Credit Card Draft
Locate - Outage Notification	Budget Billing
Carbon Monoxide	Consolidated Billing
Project Share	Time of Use Rate
Mindspring - Internet Service	Third Party Notification
Plug-In Surge Suppressors	Load Management

Subscription
Products and Services

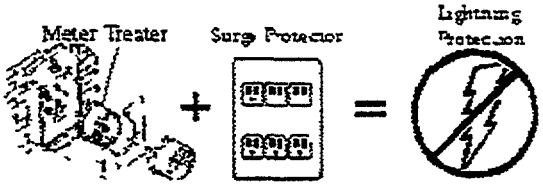
Georgia Magazine

We are proud to extend a special opportunity to our members a subscription to Georgia Magazine Sawnee EMC members can receive Georgia Magazine - the magazine for and about Georgians - at an exclusive discount price of 80 cents per issue!

Published monthly, Georgia Magazine offers feature stories about unusual people and places in Georgia, plus information on "Georgia Getaways", energy tips and new products in "Currents", gardening tips in "Georgia Gardens", delicious recipes, challenging crossword puzzles and much more! Click HERE to sign-up

Meter Treater - Whole House Protection

Sawnee EMC now offers a guaranteed way to protect your motorized electric appliances and equipment. Meter Treater is a whole house lightning protection system installed directly on your electric meter There is nothing to purchase, and for a low monthly fee of $5 50, Sawnee will install and maintain this protection system for you In addition, you can maximize the protection of your sensitive electronics with our individual plug-in devices



Because lightning can enter your home not only through power line, but also cable TV and telephone lines, additional protection is essential Click HERE to sign-up

Locate - Automatic Outage Notification

Ever wish Sawnee EMC could know instantly when your electricity goes off? Now we can!

Sawnee has a new outage notification system called "LOCATE" that will automatically report

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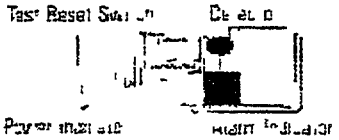
outages for you 24 hours a day, 365 days a year This small unobtrusive device plugs into one of your electric outlets and telephone jacks When loss of power occurs, it will promptly phone our computer system We quickly learn of the outage and begin working to restore your service

This exciting new program will only cost $5 95 a month for the service Installation takes only minutes, and we ship everything directly to your home, so call today! Click HERE to sign-up

Carbon Monoxide Detectors

People poisoned by low levels of carbon monoxide often mistake resulting headaches, dizziness and nausea for developing flu At high levels carbon monoxide can be fatal withing minutes Carbon monoxide when fuel burns with not enough air We recommend these preventative steps

- Yearly HVAC system inspections
- Professional chimney and flue cleaning
- Not running a gasoline engine in an enclosed space



Most important, equip your home with one UL-approved carbon monoxide detector for each sleeping area You can get a top-rated American Sensors mode 1 form us at a special rate You'll find these easy to install, just plug into any outlet Click HERE to sign-up

Project Share

Project Share is a program established by The Salvation Army in cooperation with the Electric Utility Compa- - in Georgia to address the energy-related emergency needs of low and fixed income pe sons, elderly, disabled, and other identified individuals Emergency needs include Food, shelter, clothing, medical, and utility bills Click HERE to sign-up

Mindspring - Internet Service

Members of Sawnee EMC can now receive discounted rates from a leader in Internet Service Providers with Mindspring This unique service enables Sawnee Members to receive one of t available service plans at a special rate

MindSpring

1 "The Standard" Service
Features

$13 45 for the first 20 hours (normally $14 95)
A low $10 00 Start-up fee (normally $25 00)
Personal Account (to be used only by the member and members of the immediate family)

2 "The Works" Service
Feature

995

$24 25 for unlimited use (normally $26 95)
A low $10 00 Start-up fee (normally $25 00)
Includes 10MB of Web/FTP space
Includes two extra mailboxes
Personal Account (to be only by the member and members of the immediate family)

Another great benefit of membership at Sawnee EMC! Click HERE to sign-up

Plug-In Surge Suppressors by Panamax.

As home electronics and appliances become more and more sophisticated, they have also become more sensitive to normal electric occurrences Voltage surges are short periods of high voltage or "spikes" of electricity that occur through power lines, telephones, TV antennas and cable TV lines Even when equipment is turned off, voltage surges can affect home electric equipment

Sawnee EMC offers plug-in surge suppressors by Panamax Three protection packages are available

- Two Outlet (Max 2 $48 00)
- Two Outlet w/phone (Telemax 2 $50 00)
- Six Outlet w/catv (Coaxmax 6 $76 00)

To receive your surge suppressor click HERE

Basic

Products and Services

Bank Draft

Bill paying by Bank Draft will reduce the number of checks you write each month Under Sawnee's Bank Draft program you pay no fee to use the service and we draft your account on the last possible day A statement will be printed at the bottom of the bill telling you that your bill will be drafted on a certain date Budget billing makes paying your energy bill quick, convenient, and easy To sign up for Bank Draft click HERE

Credit Card Draft

It just keeps getting easier to pay your bills at Sawnee EMC And we're taking convenience a step further with our Credit Card Draft program This program is designed to enable you to pay your electric bill via your credit card (MasterCard, Visa, Discover, American Express, or Bank Debit Card) and never have to write a check or come to our office to pay

You will continue to receive a monthly bill and the message "your bill will be paid by credit card" will be printed on it Under Sawnee's Credit Card Draft program you pay no fee to use the service and we draft your account on the last possible day To sign up for Credit Card Draft click HERE

Budget Billing

Wouldn't it be nice to know the exact amount of your bill every month *before* it arrives? Well, now you can! Sawnee EMC offers Budget Billing which allows twelve (12) months Whether it's

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summer, winter, spring or fall, you'll enjoy the comfort and convenience of a predictable electric bill To sign up for Budget Billing click HERE

Consolidated Billing

This service is designed for members who receive two or more electric bills from us in one day With consolidated billing, we continue to show the energy usage and bill amount for each separate account, however, it will be on one bill form If you receive two or more bills in the same day and would like Consolidated billing click HERE

Time of Use Rates

The Time-of-Use rate (TU-12) for residential members is offered by Sawnee EMC to any member wishes to participate The rate was designed to encourage consumers to shift electric usage form peak times to off-peak times The usage of appliances such as the washer, dryer, dishwasher, and oven are some of the loads which could potentially be shifted to off-peak times TU-12 was also designed to discourage the use of major electric appliances such as an air-conditioner or heat pump during peak times To sign up or learn more about TU-12 click HERE

Third Party Notification

If someone you care about sometimes forgets to pay his or her electric bill, we can make you part of our Third Party Notification program With the consent of the party involved, we can notify you of any risk of disconnect for no-payment To sign up for this program click HERE

Load Management

The Load Management switch is for those who want to help keep energy costs down It is an excellent opportunity for all consumers with an electric central air conditioner or heat pump and/or electric water heater to take part in controlling the costs of electricity We will install and maintain the switch free of charge plus give a $10 00 energy credit for an air conditioner and heat pump and $5 00 for the water heater switch To have your Load Management switch installed and to receive your energy credit(s) click HERE

POWER

MARKETING

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POWER MARKETING

Power Marketing

- An Up and Coming Business in the US
- Many New Faces Are Appearing in the Electric Industry
- And Many Old Faces Are Getting Face Lifts

Power Marketing Positions Taken

- Enron Corporation - Houston Texas
  - 13 Billion in Revenues
  - International electricity and gas marketing giant that is moving into deregulated local retail markets. Pilot program in New Hampshire; acquiring Portland General Electric.

» Time, March 10, 1997

Power Marketing Positions Taken

- The Southern Company
  - 10.4 Billion in Revenue
  - Invented a computerized energy tracking system licensed to other utilities. Developing interactive energy management systems for consumers. Expanding to New England and into natural gas distribution

» Time, March 10, 1997

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Power Marketing Positions Taken

- Pacific Gas & Electric
  - 9.6 Billion in Revenues
  - Wants to go global and has set up a holding company to make acquisitions. Bought three natural gas companies in Texas and a pipeline in Australia; selling four California power plants.

» Time, March 10, 1997

Power Marketing Positions Taken

- Duke Power
  - 4.7 Billion in Revenues
  - A pending merger will move it into natural gas in the Northeast and Midwest. Joint venture with commodities giant Louis Dreyfus to market power nationally.

» Time, March 10, 1997

Power Marketing Positions Taken

- Boston Edison
  - 1.7 Billion in Revenues
  - Getting out of power generations and into telecommunications and natural gas through two joint ventures. Will sell telephone, Internet, video and energy services.

» Time, March 10, 1997

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Power Marketing Questions To Ask??

- What if My Load Forecast is High?
- What if My Load Forecast is Low?
- What About Reliability?
- What is Your Interest in Utilities?
- What is the Length of the Contract?
- Terms of Contract With Customers

Power Marketing

- IN THE US, THE ELECTRIC UTILITY INDUSTRY IS CHANGING FROM MINUTE TO MINUTE.
- POWER MARKETERS ARE MOUNTING MASSIVE MARKETING AND SALES CAMPAIGNS TO OUR CUSTOMERS.
- CHANGE IS INEVITABLE

Power Marketing

- Our Company is Positioning Itself To Be a "Wires" Company Regardless of Who Owns the Electrons.
- Preach Customer Service

DAY 5

8 00 - 9 00	SCADA Overall Plan Distribution Automation Load Management	Mr Billy Ussery
9 00 - 10 00	GIS / AM-FM Systems	Mr Billy Ussery
10 00 -10 15	Break	
10 15 - 12 00	Field Communications	Mr Billy Ussery
12 00 - 1 00	Lunch	
1 00 – 3 00	Wrap Up and General Discussion/Questions	Mr Billy Ussery

SCADA

Supervisory Control And Data Acquisition

SCADA

SCADA

- Define The Need
- Determine The Method Of Communications
- Determine The Specifications For The System
- Consider SCADA Related Functions

SCADA

- A Very Powerful Operational Tool
  - Real Time Data Flow
  - Real Time Detection of Problems
  - Immediate Corrective Action
  - Many Times Service Can Be Restored With No Field Visit

SCADA

- Define The Need
  - Easily Done From An Engineering / Operations View Point
  - Immediate Access and Data To Remote Sites
  - Voltage Conditions
  - Current Loading
  - Status of Breakers
  - Unlimited Data Collection

SCADA

- Method of Communications
  - Most Important Consideration
  - Will Narrow The Search For Systems
  - Will Also Determine Other Important SCADA Related Activities
  - Possible Alternatives
    - Radio
    - Telephone
    - Fiber Optics

SCADA

- Determine the System Specifications
  - Think Long Term
  - Consider Optional Systems
  - How Many Users
  - Graphics
  - User Friendly
  - Cost

SCADA

- SCADA Related Functions
  - Load Management
  - Distribution Automation
  - Capacitor Switching
  - Interactive Mapping
  - Outage Notification
- Communications is Key For Each Function

SCADA

- Popular Vendors
  - Advanced Control Systems (ACS)
  - Valmet
  - QEI
  - Siemens
  - Landys & Gyr
  - Many Others

SCADA

- System Support
  - Electronics / Communications Specialist
  - System Programmer
  - Continuous Maintenance

SCADA

- Conclusion
  - Aids in System Planning
  - System Operations
  - System Maintenance
  - Valuable for Reliability

COMMUNICATIONS

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FILE'D COMMUNICATIONS

Field Communications

- Important For Safe Operation Of The System
- Types of Communication
- Who Has Communication
- Feasibility of Data Transmission
- Real Time Updates and Reporting

Field Communications

- An Important Safety Factor While Operating The System
- May Be Used In Switching
- Contact Crews For Emergency Work
- Daily Work Schedule Changes
- ETC

Field Communications

- Types Of Communications
  - Low Band
  - High Band
  - 800-900 MHz
  - Cellular
  - Private Cellular Type System
- Must Consider Terrain and Service Area

Field Communications

- Who Has Communications
  - All Outside Personnel
  - Dispatchers / Control Center
  - Engineers
  - Key Office Personnel
  - Contractors

Field Communications

- Data Transmission
  - Consider Feasibility of A System That Can Transmit Data
    - New Service Requests
    - Text Messaging
    - Outage Information
    - Meter Readings
    - ETC.

Field Communications

- A Very Simple Concept
- But Very Important
- Cost Can Vary Drastically From Low To High

GIS/AM-FM SYSTEMS

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GIS / AM-FM SYSTEMS

GIS / AM-FM SYSTEM

- What Is It??
  - Geographic Information System
  - Automated Mapping - Facilities Management System

GIS / AM-FM SYSTEM

- Mapping
  - Maps Are "Field Inventory Systems'
  - Aids in Engineering Staff Design
  - Operation of System
  - Customer Locations
  - System Planning

GIS / AM-FM SYSTEM

- Mapping
  - Establish Standardized Symbols
  - Establish Accurate Backgrounds
  - Establish Existing System Information
  - Establish Procedures For Upkeep and Maintenance of the Mapping System

GIS

- Geographic Information Systems
  - Determine If Right For Your Company
  - Determine If Feasible
  - Usually Includes
    - Global Positioning
    - Specific Sites Tied to Given Coordinates
    - Some Facilities Data Is Included

AM

- Automated Mapping
  - Usually Consists of Electronic Database of Maps
  - Divisions of Layers Within The Maps
  - Can Be Updated In The Field Or In The Office
  - Can Be Linked to Other Systems
    - Staking Outage Analysis SCADA
    - Customer Service

FM

- Facilities Management
  - Consists of Maintaining A Database of All of the Facilities On The System Within The Mapping Files
  - Must Determine Feasibility
  - Maintenance of the Databases Has To Be Considered - Very Labor Intensive
  - Tendency to Get Out Of Date Files

GIS / AM -FM SYSTEM

- Can Be A Valuable Asset To Company
- Recapping
  - Benefits Operations
  - Benefits Engineering
  - Benefits Planning
  - Benefits In Restoration of Service

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

BULLETIN 1724D-103

SUBJECT: System Planning Guide, System Mapping Guide

TO: REA Electric Borrowers and REA Electric Staff

EFFECTIVE DATE: Date of Approval

EXPIRATION DATE: Three years from effective date

OFFICE OF PRIMARY INTEREST: Distribution Branch, Electric Staff Division

FILING INSTRUCTIONS: This Bulletin replaces Bulletin 40-4, "Guide Mapping and Location Numbering, Electric Distribution Systems," dated July 8, 1974, which was rescinded by REA on December 18, 1991. File along with 7 CFR 1724 in the blue binders

PURPOSE: The purpose of this bulletin is to provide guidance to borrowers and engineers for the preparation of various maps and system diagrams required for facilities identification and location, planning and the operations of the electric distribution systems.

Administrator

7/19/93
Date

1038

TABLE OF CONTENTS

1. Introduction

2. Purpose

Exhibit: Mapping Symbols

INDEX: System Planning Guide

1. **Introduction:** A series of symbols, and their definitions, pertaining to electrical lines, equipment, facilities and appurtenances used on electric utility power systems, and geographic and political mapping symbols and their definitions has been developed They are attached to this bulletin as "Mapping Symbols."

1.1 It is suggested that REA electric borrowers adopt these symbols as a standard and use them on maps and system diagrams which are furnished to REA for various reasons.

1.2 It is anticipated that the adoption and use of these standard symbols will improve clarity and expedite reviews of maps and system diagrams furnished to REA.

2. **Purpose:** The purpose of this bulletin is to provide guidance to borrowers and engineers for the preparation of various maps and system diagrams required for facilities identification and location, planning and the operations of the electric distribution systems.

POLE

MEMBER

IDLE SERVICE

LIGHT

FUSE 25 25

SWITCH add (no)

ABS	ADD	ABS OR GOAB
MOTOR OP.	ADD	MO
LOAD BREAK	ADD	LB

SUB/METERING POINT SUB NUMBER MP 14 NAME MVA VOLTAGE

GENERATOR UNIT NUMBER 4 NAME MW TYPE

TRANSMISSION LINE OWNER VOLTAGE

SECONDARY JUNCTION PEDESTAL

SECONDARY JUNCTION PEDESTAL UG

104

VOLTAGE DROP BLOCK

UNREG	12.7
REGULATED	4.2
MILES FROM SOURCE	27.2

PRI /AUTO TRANSFORMER

ALL WIRE ACSR UNLESS OTHERWISE LABELED

SIN PHASE

V PHASE

THREE PHASE

SECONDARY 1/0

PRIMARY UNDERGROUND

SINGLE PHASE U

V PHASE U 2

THREE PHASE U 3

SECONDARY UNDERGROUND U 4/0

CULTURAL FEATURES

INTERSTATE HIGHWAY

U.S. ROUTE

STATE ROAD

FARM TO MARKET ROAD

COUNTY ROAD

UNIMPROVED ROAD

RAILROAD

ELECTRIC RAILWAY

TELEPHONE

FIBER OPTIC TRUNK LINES

BRIDGE

CITIES AND TOWNS (within corporate limits)

TOWNS AND VILLAGES

STATE CAPITAL

COUNTY SEAT

HOUSES AND OTHER BUILDINGS

SCHOOL

CHURCH

HOSPITAL

FACTORY

CAMP

DOCK

CEMETERY

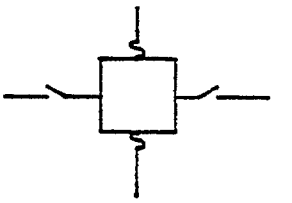
WINDMILL

OIL OR GAS WELLS

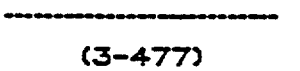
MINE OR QUARRY

JUNCTION BOXES

SWITCH BOX



PROPOSED
CIRCLE/BOX/CLOUD AROUND PROJECT



OPEN

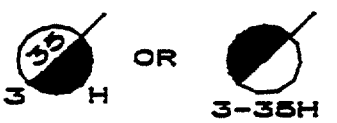
CAPACITOR SHUNT

CAPACITOR SERIES

REGULATORS

STATION BREAKER

RECLOSERS



SECTIONALIZER

TRANSFORMER

PAD MOUNTED TRANSFORMER

BOUNDARIES

STATE LINE & INTERNATIONAL BOUNDARY

COUNTY LINE

TOWNSHIP LINE

SECTION LINE

LATITUDE & LONGITUDE LINES

RESERVATIONS, NATIONAL & STATE FORESTS & PARKS

PROJECT BOUNDARY

TERRITORY BOUNDARIES

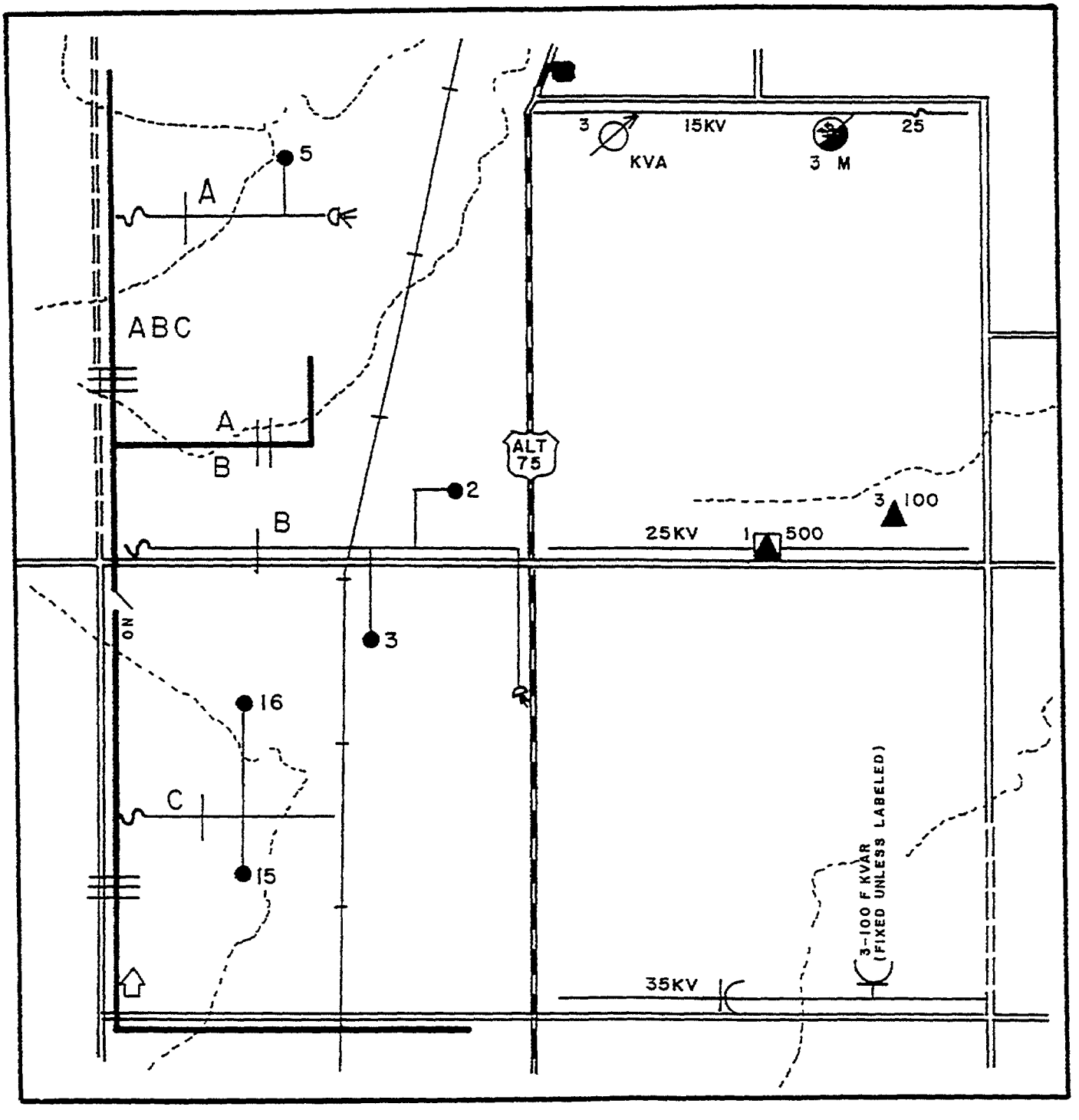
CITY LIMITS

PIPE LINE

AIRPORT

LOCATED OR LANDMARK OBJECT

TRIANGULATION STATION
USGS BENCH MARK ADD B.M.


3
15KV
25
KVA
3 M
5
A
ABC
A
B
ALT
75
2
3 100
B
25KV
1 500
ON
3
16
C
15
3-100 F KVAR
(FIXED UNLESS LABELED)
35KV

1947

WRAP-UP

GENERAL DISCUSSION/QUESTIONS

Wrap Up

Wrap Up

- All In All The Utility Industry Is Changing Rapidly
- Can Be An Exciting Industry

Wrap Up

- Many New Issues Facing Us
- Deregulation
- Power Marketing
- Much More Advanced Society

- Always Remember.....

CUSTOMER SERVICE
CUSTOMER SERVICE
CUSTOMER SERVICE

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QUESTIONS AND GENERAL DISCUSSION

SUPPORTING

REFERENCE

MATERIAL

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Electric Utility Knowledge Handbook

POWER•UP

Electricity

FROM GENERATION TO DISTRIBUTION

HOUSTON LIGHTING & POWER COMPANY

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Acknowledgement

We would like to thank the following people who contributed their time and effort to the successful completion of Power Up! Electric Utility Knowledge

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The Generation, Transmission, and Distribution of Electricity at HL&P

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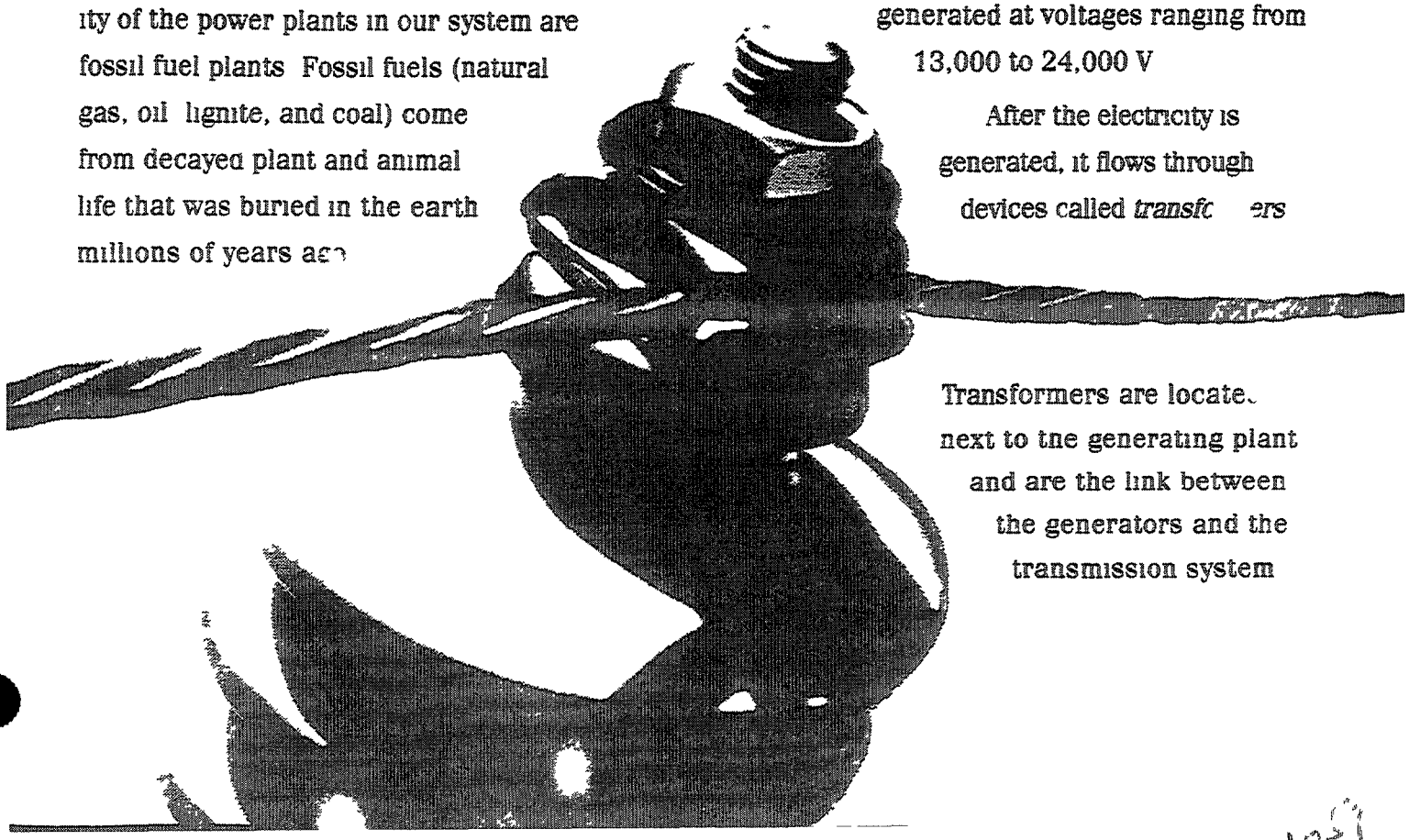
ELECTRICITY

Electricity is the flow of electrons Electrons are tiny particles found in all atoms Atoms of some metals, such as copper and aluminum, have electrons which are ea ly pushed and guided into a stream When a l of metal wire is turned near a magnet electricity will flow in the wire This same principle is used in power plants to make large amounts of electricity

System wide, HL&P's power plants use a variety of energy sources However, the majority of the power plants in our system are fossil fuel plants Fossil fuels (natural gas, oil lignite, and coal) come from decayed plant and animal life that was buried in the earth millions of years ago

Fossil fuel plants produce commercial electricity by igniting a fossil fuel in the furnace section of a boiler Water is piped thr gh the boiler in large tubes The water is superheated and converted to steam The steam turns turbine blades which are connected by a shaft to a generator The generator (a huge electromagnet surrounded by coils of wire) produces electricity when it rotates The push (or pressure) forcing the electricity from the generator is measured in volts (V) Ele icity is generated at voltages ranging from 13,000 to 24,000 V

After the electricity is generated, it flows through devices called *transfo ers*



Transformers are locate next to the generating plant and are the link between the generators and the transmission system

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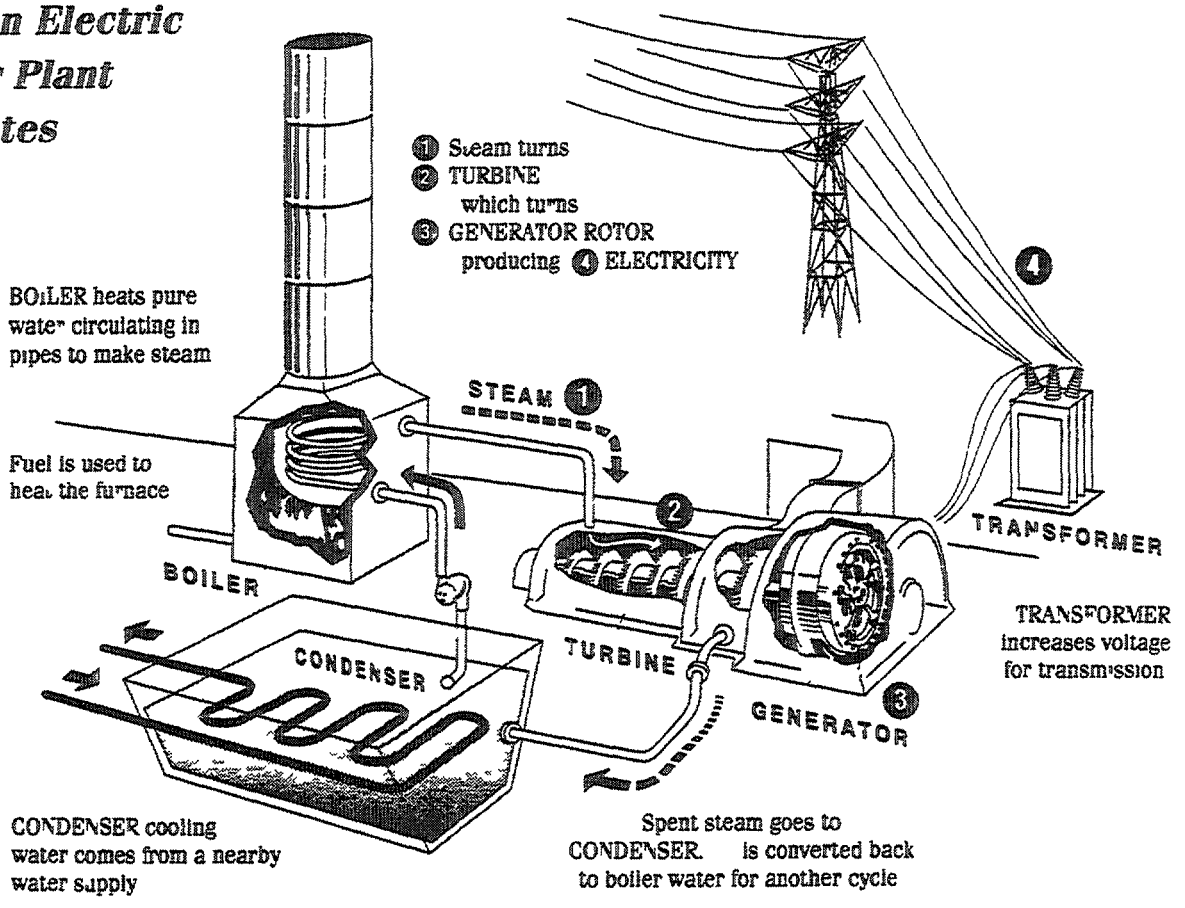
How an Electric Power Plant Operates



In much the same way a pump builds water pressure, transformers step up the electrical voltage to levels ranging from 69,000 to 345 000 V, depending on the distance the electricity must travel and the amount of power needed

Once the electricity is given enough push (voltage) it enters the transmission and distribution grid, an electrical transportation network much like a highway system

All this happens in an instant Electricity travels at the speed of light — 186 000 miles a second That's like traveling 7½ times around the world in one second

Since electric power cannot be stored it must be delivered to the customer at virtually the same moment it's produced The first link in delivering electricity is the *transmission system*

Transmission System

In the electric utility industry, transmission lines are the high voltage conductors that carry electricity from the power plant to substations and from one substation to another

Above-ground lines are supported by transmission towers, usually made of steel These transmission towers must be strong enough to support the high voltage wires, as well as insulators and switches, even when high wind or ice create additional stress Although transmission towers come in many shapes and sizes, as a general rule, the taller the tower, the higher the voltage

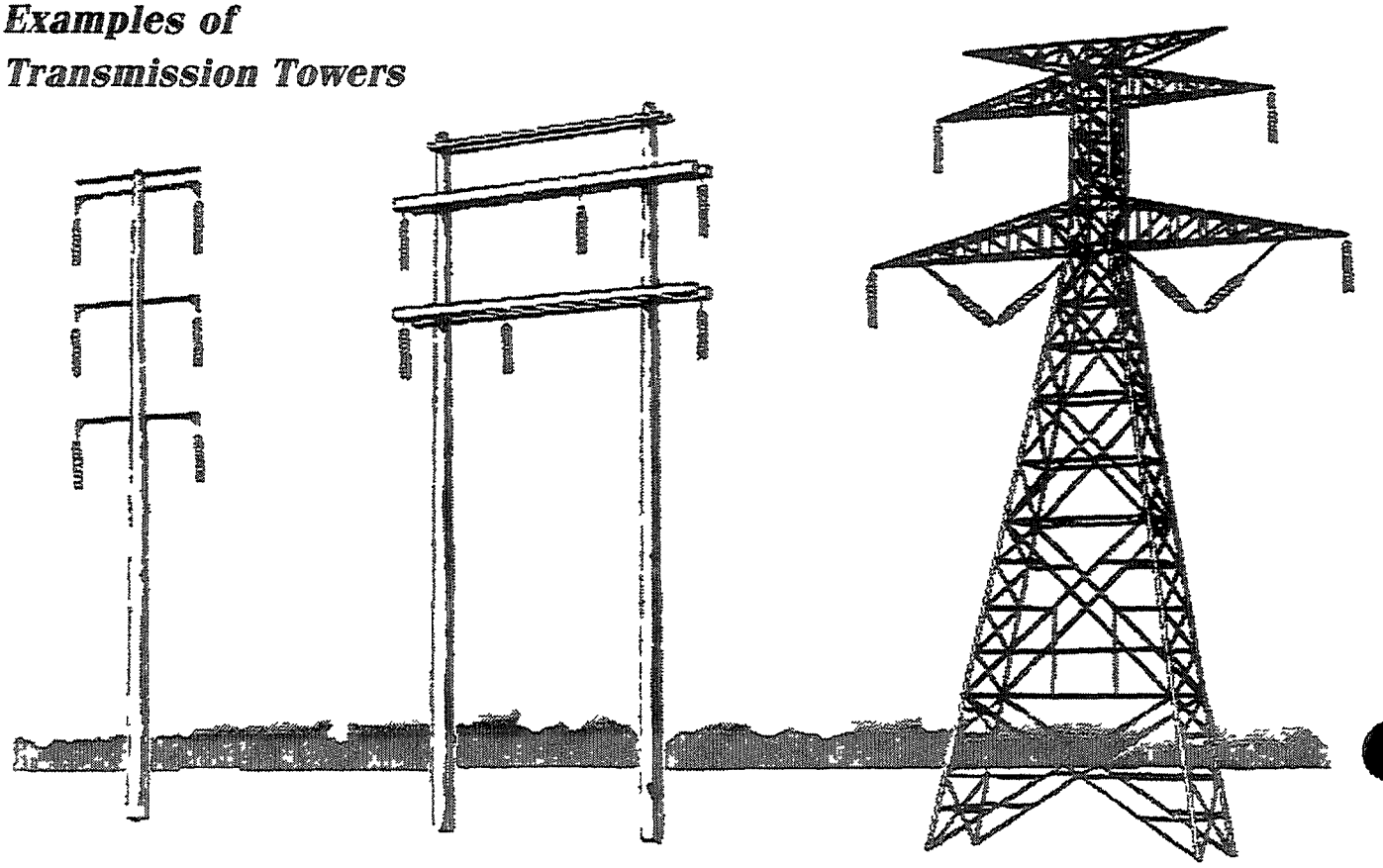
Transmission wires are connected to the towers by insulators which are often made from glass or porcelain because of their non-conductive properties The amount of insulation depends on the voltage — higher voltages need longer insulators

Transmission lines carry a three-phase current In other words three separate streams of electricity travel along three separate conductors within the line The transmission lines in our system are interconnected to form a network Should one line fail another will take over the electric load

HL&P's transmission system is connected with the transmission systems of other electric utility companies in Texas through a state-wide network of transmission lines called a *grid* If we need an emergency supply of electricity (or if another utility needs our electricity), we can send or receive power through this grid

As power is generated and routed along transmission lines it passes through the second link in the system — *substations*

Examples of Transmission Towers



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Substations

Substations serve as junction points, or interchanges, along the electrical network They connect power plants, high voltage transmission lines, and the lower voltage distribution lines

Substations serve two main functions in the system (1) to switch transmission circuits, and (2) to step voltage down to appropriate levels for distribution

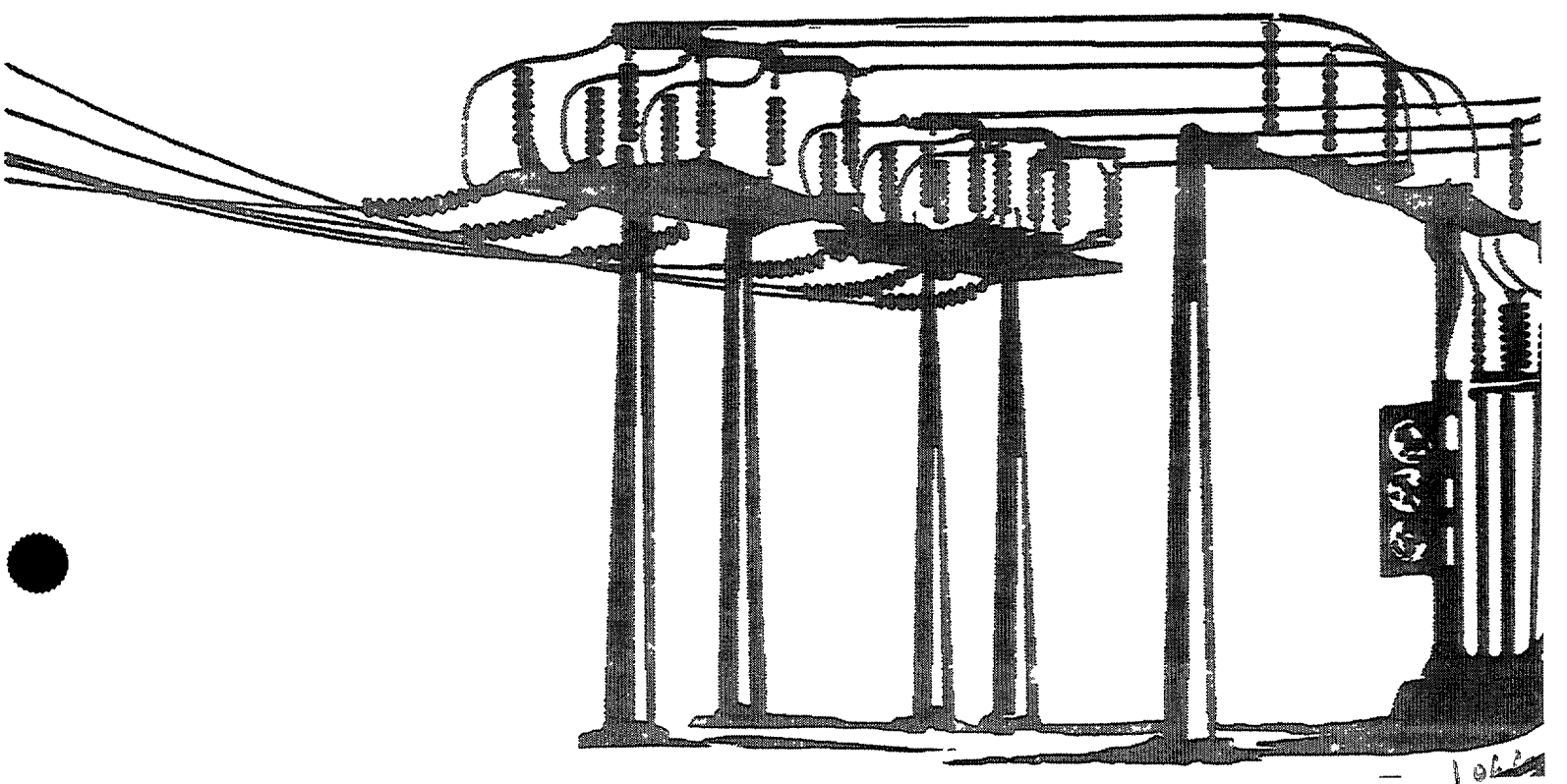
The transmission system is designed as a network with multiple paths As a result, when transmission circuits are switched out power continues to flow to where it's needed through alternate paths This switching and rerouting takes place at substations In this way, HL&P provides efficient, reliable service to customers, even during peak demand periods and crisis situations caused by storms

While some transmission lines pass through a substation, others are tapped for distribution to customers To do this, substation transformers connect transmission lines with primary distribution lines The transformer lowers, or "steps down," the voltage so it can be carried on the smaller lines

Substations also house circuit breakers These breakers are controlled by other devices called relays Relays monitor conditions on the transmission and distribution lines and signal breakers or other protective devices to open and close as needed

Substations are not staffed An HL&P crew is dispatched to a substation only if a problem is detected, or if switching or maintenance is needed

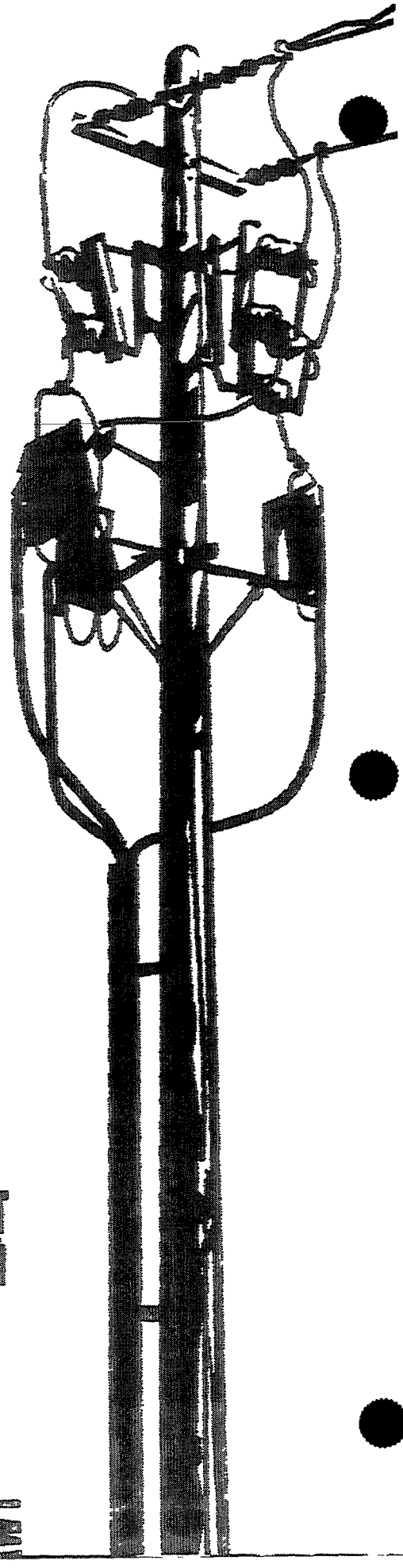
From the substation electricity is delivered to the customer through the *distribution system*

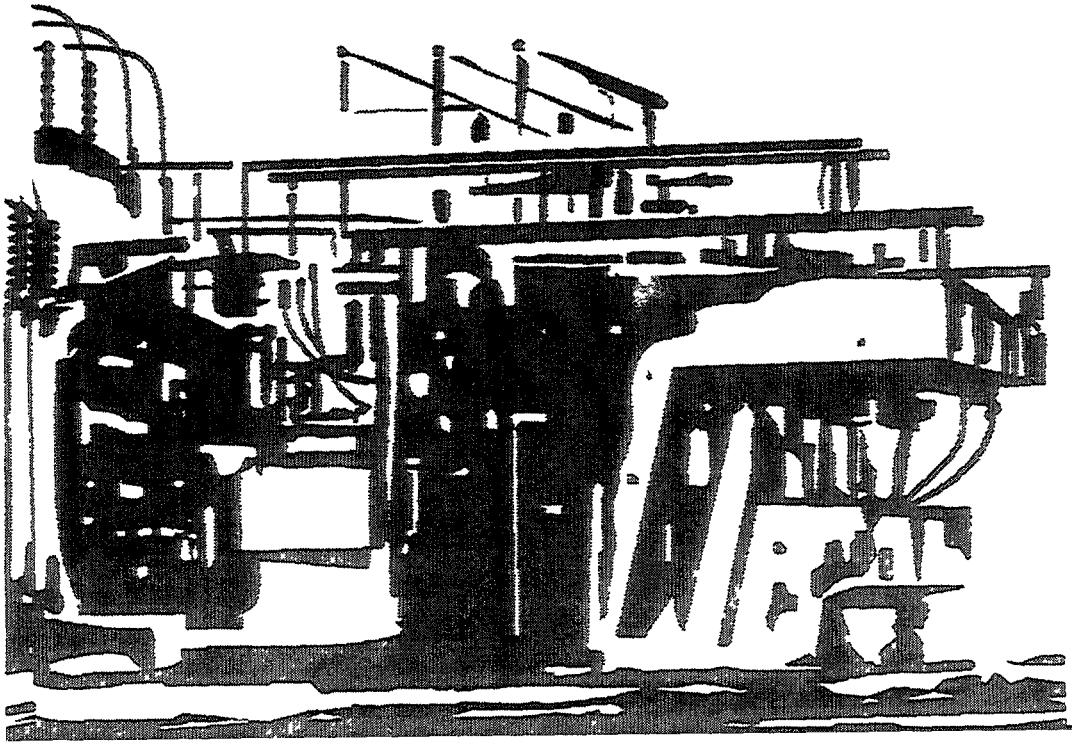


Distribution System

Unlike the transmission system which carries high voltage electricity over great distances distribution lines carry lower voltage power from the substation to the customers These are the power lines commonly seen along streets and in residential areas

The distribution system consists of primary distribution lines, transformers secondary distribution lines, and service wires





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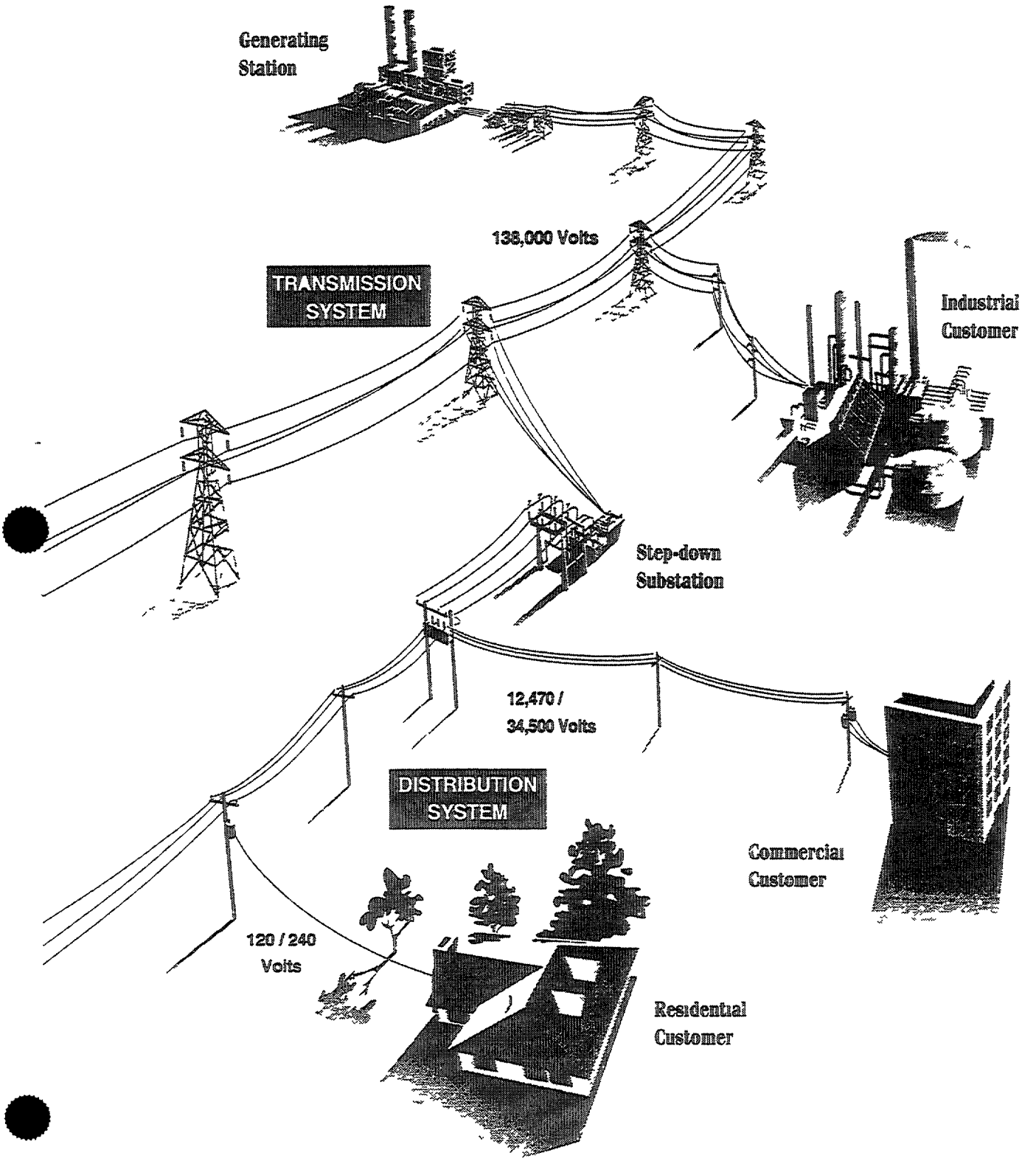
HL&P Electric Service System



POWER PLANT SUMMARIES

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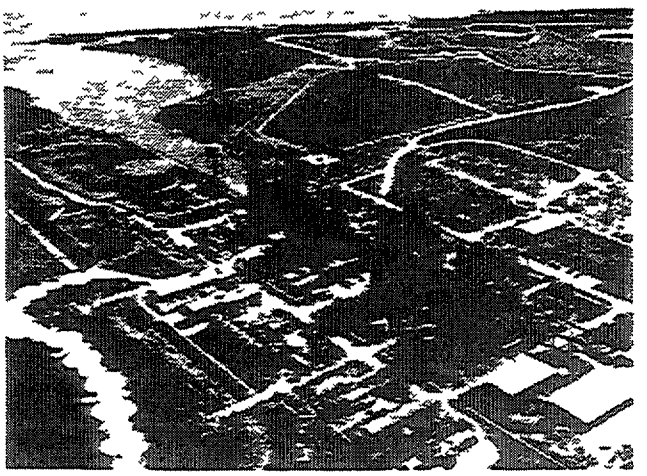
POWER PLANT SUMMARY

S.R. BERTRON

STEAM ELECTRIC GENERATING STATION



Plant Data

- S R Bertron is located on a 664 acre site on Miller Cut-Off Road The site is just southeast of the San Jacinto Monument
- The plant consists of four steam units and two gas turbines and began commercial operation on March 1, 1958
- The primary fuel for this plant is natural gas supplied by outside vendors No 2 fuel oil is the secondary fuel for the plant

Cooling Water

- Cooling water for the main condensers is obtained from the Houston Ship Channel through a 0 6 mile long intake canal Cooling water for turbine lube oil, generator hydrogen cooling, and miscellaneous cooling is fresh water circulated through a 6-cell cooling tower
- Surface water from the Trinity River is used for cooling tower makeup (water to replace that lost through evaporation and other factors) and for the makeup demineralizer Wells supply potable water and serve as backup for the surface water supply

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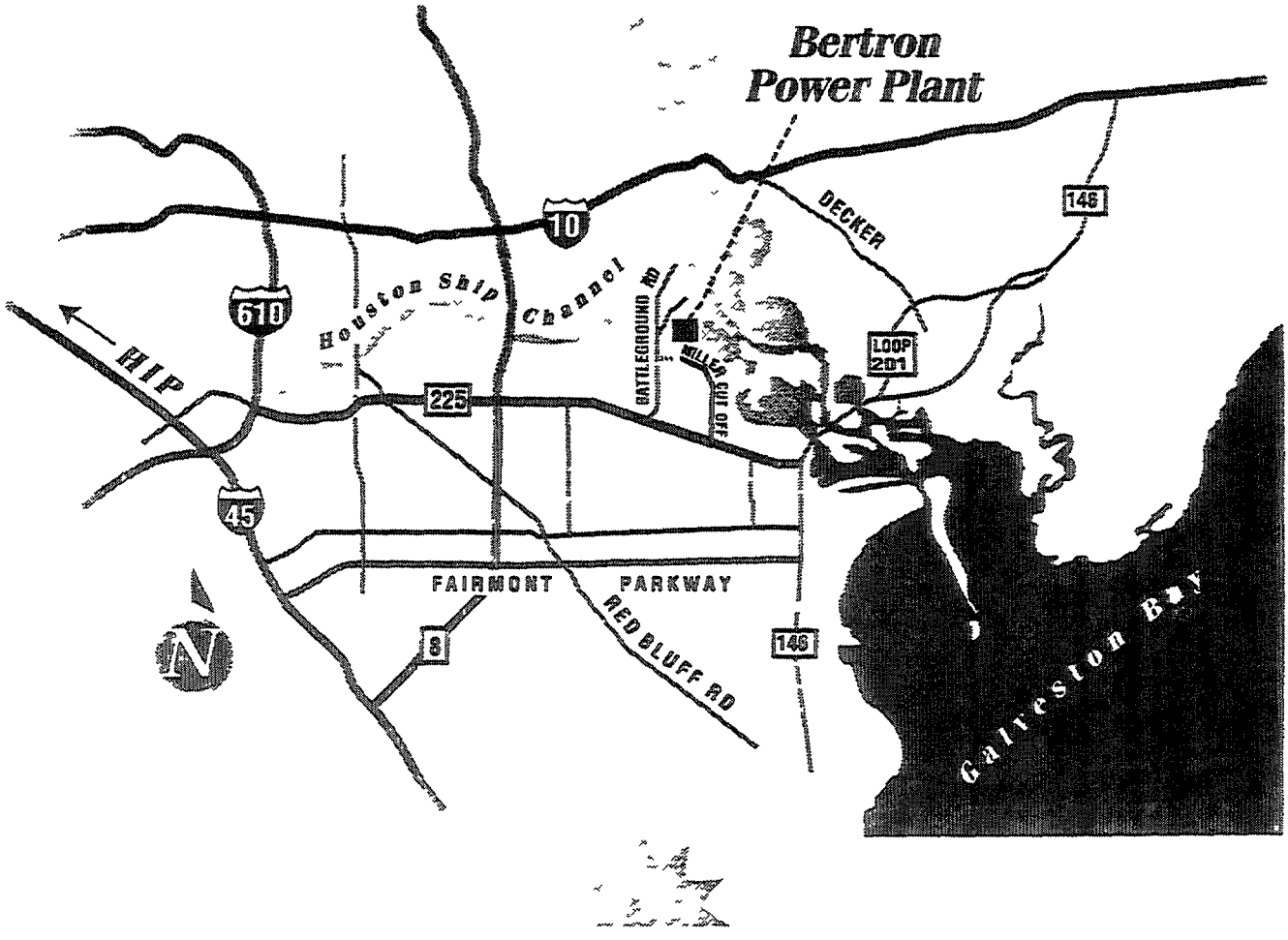
Hurricane Protection

- For protection against tidal surges, the plant is surrounded by a hurricane protection system This system is comprised of earthen levees, concrete walls and a sheet piling cofferdam with controllable gates to contain tides up to 20 feet elevation

Pollution Control

- Four earthen ponds and two concrete basins located north of the plant entrance are used for wastewater containment They hold blowdown water, boiler cleaning water, clarified water and demineralizer regeneration wastewater Sanitary wastewater is processed in a septic treatment system on-site
- API oil separators/tricellerators trap, skim and store waste oil This waste oil is periodically recycled or disposed of offsite by a waste handling and processing company
- Hazardous wastes are collected and disposed of offsite by a licensed contractor



POWER PLANT SUMMARY

CEDAR BAYOU

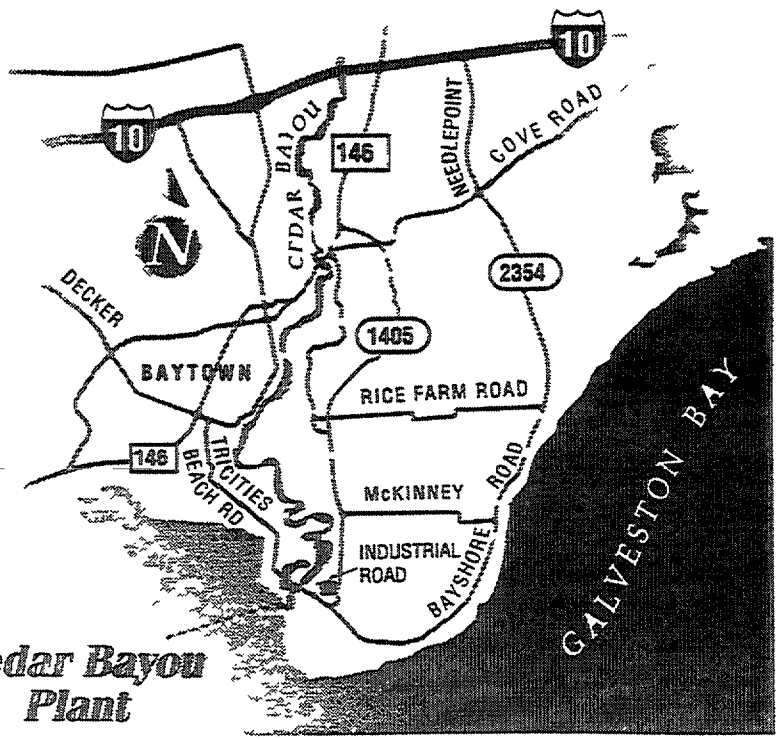
STEAM ELECTRIC GENERATING STATION

Plant Data

- The Cedar Bayou Generating Station is located on a 344 acre site east of Baytown, Texas, on FM 1405
- The plant consists of three supercritical steam generators and began commercial operation in December of 1970
- The primary fuel for the plant is natural gas supplied by outside vendors with fuel oil serving as a backup

Cooling Water

- Cooling water for the main condensers is obtained from Galveston Bay via Cedar Bayou The discharge canal is approximately 6 miles long and terminates at a drop structure where the water enters a 2 600 acre open-cycle cooling pond After a 4-day trip through the cooling pond, the water discharges into Trinity Bay
- Fresh water for station service, steam generator makeup, and cooling tower makeup comes from the Trinity River Two deep wells act as a backup to the river water supply Cooling towers are used for lube oil and hydrogen cooling systems



Cedar Bayou Plant

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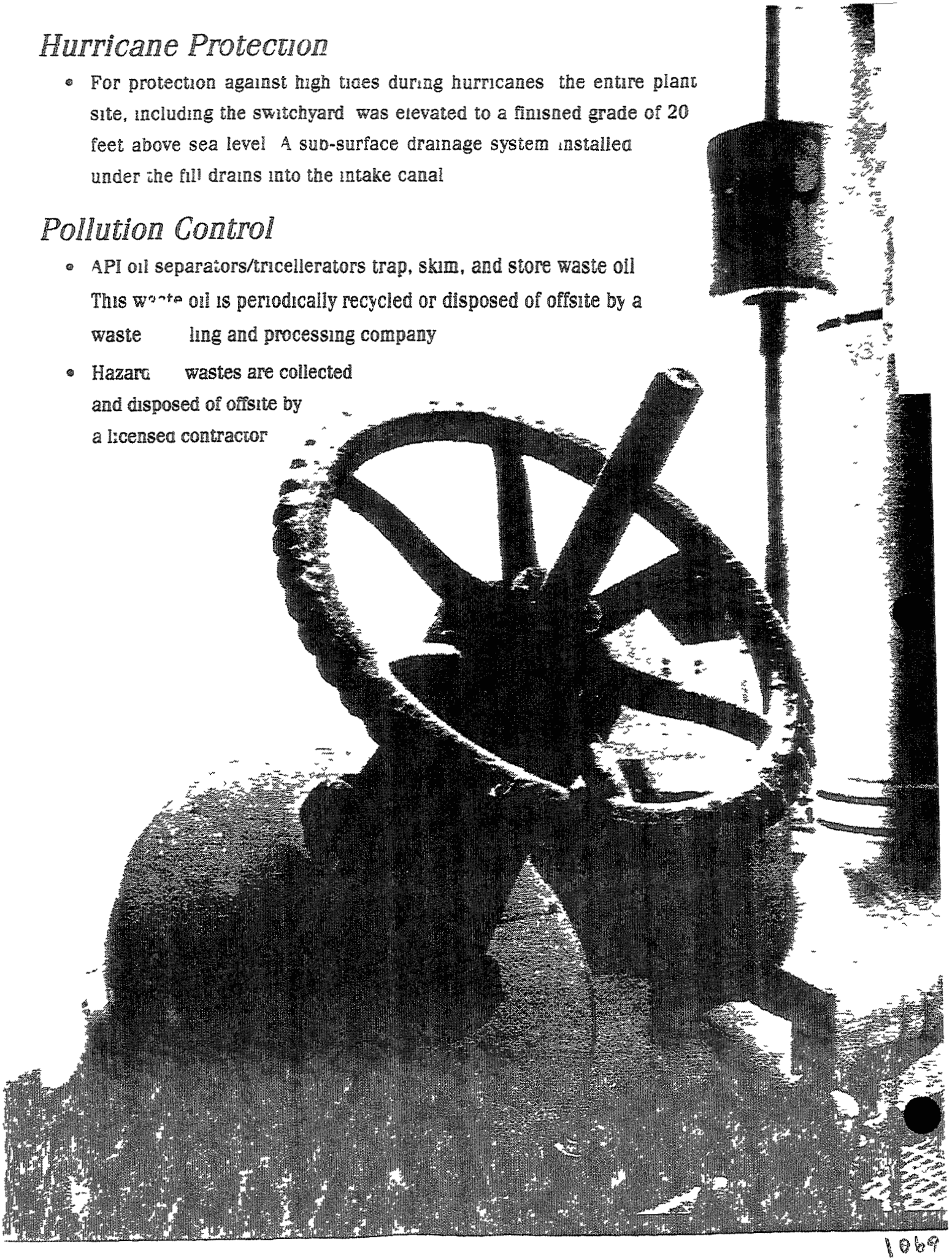
Hurricane Protection

- For protection against high tides during hurricanes the entire plant site, including the switchyard was elevated to a finished grade of 20 feet above sea level A sub-surface drainage system installed under the fill drains into the intake canal

Pollution Control

- API oil separators/tricellerators trap, skim, and store waste oil This waste oil is periodically recycled or disposed of offsite by a waste ling and processing company
- Hazard wastes are collected and disposed of offsite by a licensed contractor



POWER PLANT SUMMARY

H.O.CLARKE

ELECTRIC GENERATING STATION

Plant Data

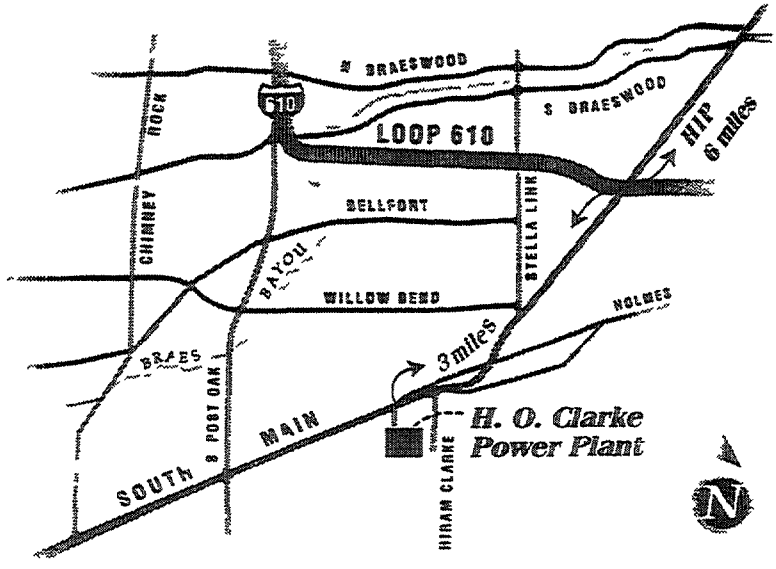
- H O Clarke Electric Generating Station is located on a 252 acre site on H O Clarke Road and South Main Street
- The plant began commercial operation in 1943 as the West Junction Generating Station In 1954, the plant was renamed to honor Hiram O Clarke, a former president of HL&P
- The plant consists of six simple cycle air cooled gas turbines The plant site also houses four retired steam units
- Natural gas supplied by outside vendors is used for fuel (*Note The gas turbines do not have fuel oil burning capability*)

Cooling Water

- Three water wells supply two settling basins and an overhead tower for fire protection Potable water is supplied by the City of Houston

Pollution Control

- Since the retirement of the four steam units, waste oil and waste water have been virtually eliminated with the exception of rainwater
- An API oil separator traps any incidental oil All other hazardous materials are collected and disposed of offsite by a licensed contractor



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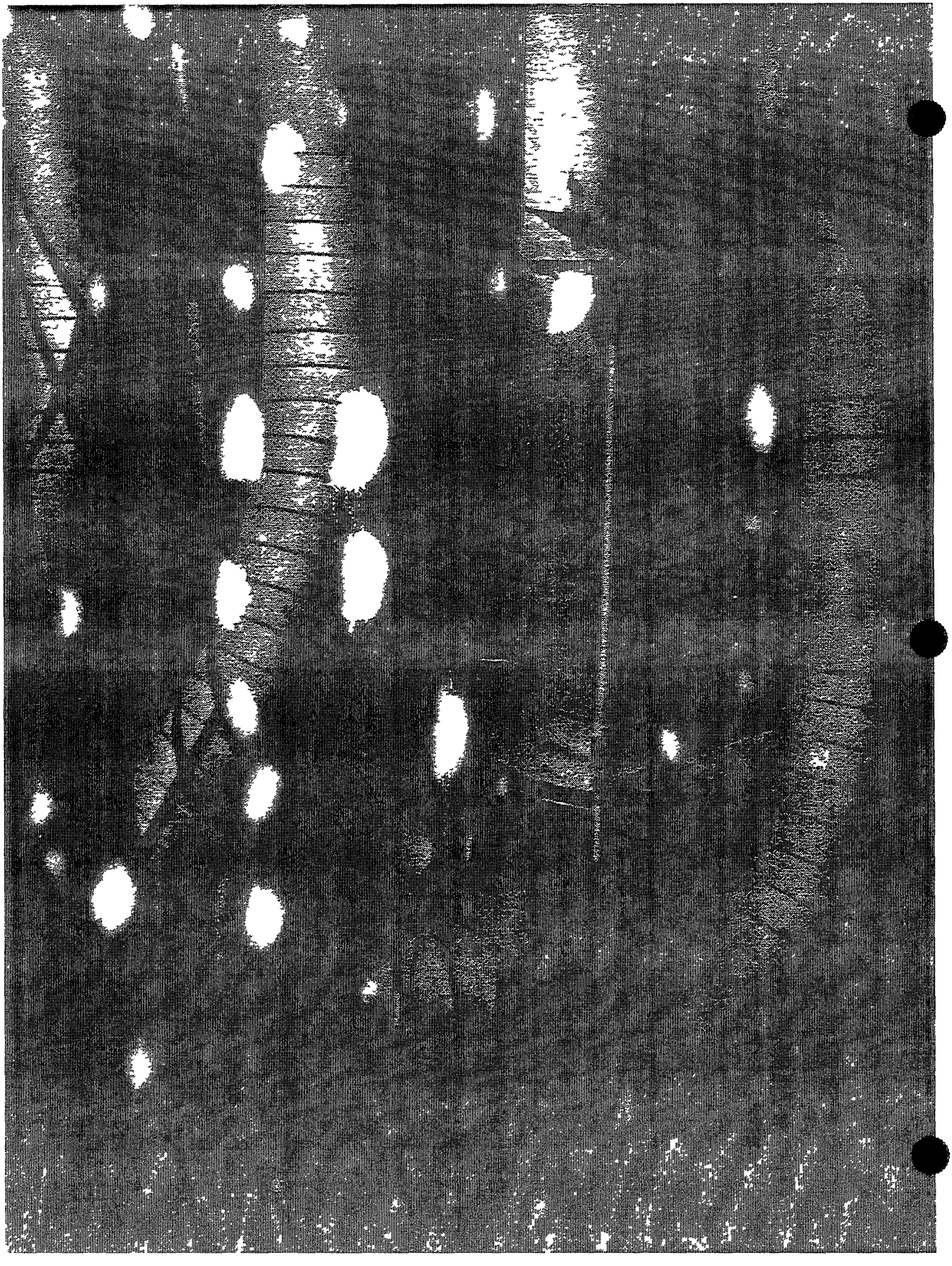

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POWER PLANT SUMMARY

DEEPWATER

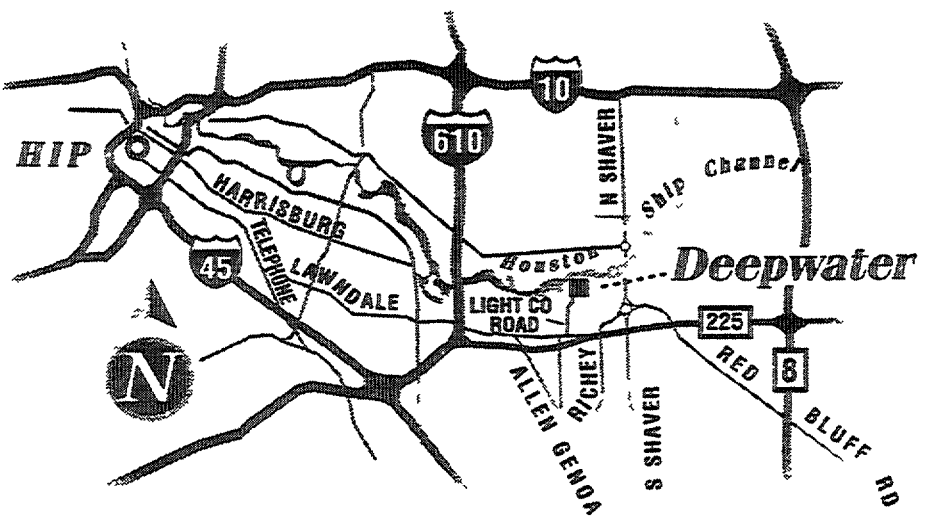
ELECTRIC GENERATING STATION

Plant Data

- The Deepwater Electric Generating Station is located on a 68 35 acre site in southeastern Harris County on Light Company Road near the juncture of the Houston Ship Channel and Vince Bayou
- The plant consists of a 183 MW steam unit converted for cyclic operation and six retired steam units Unit 1 commenced operation in 1924 and the latest, Unit 7, went commercial in 1953
- Natural gas supplied by outside vendors is used for fuel in the generating unit

Cooling Water

- Condenser cooling water is taken from the Houston Ship Channel and discharged into Vince Bayou
- Three water wells supply makeup to the settling basin for the service water system and the boiler makeup demineralizer An auxiliary cooling tower is supplied makeup from the service water system for equipment cooling and fire protection Potable water is supplied by the City of Pasadena to a separate system for sanitary and drinking purposes



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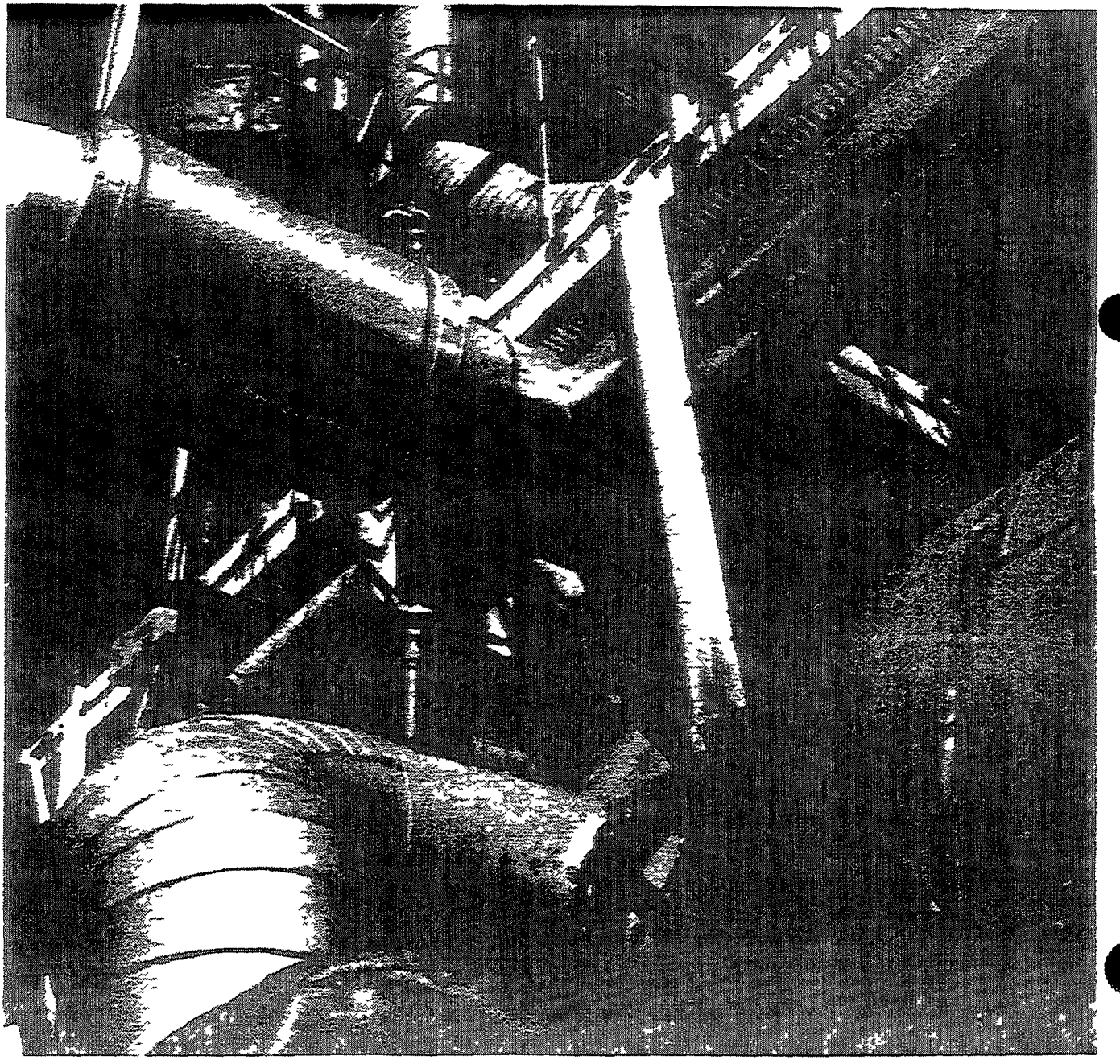
Pollution Control

- There are three waste water containment ponds for storage of boiler blowdown, demineralizer regenerant, and organic boiler cleaning wastes prior to neutralization in the Chemical Waste Treatment System (CWTS)
- Water runoff from possible oil spill areas is collected in various sumps and pumped through an API oil separator and air flotation separator system (tricellertor), to capture any oil contamination
- Hazardous wastes are collected and disposed of offsite by a licensed contractor



POWER PLANT SUMMARY

GREENS BAYOU

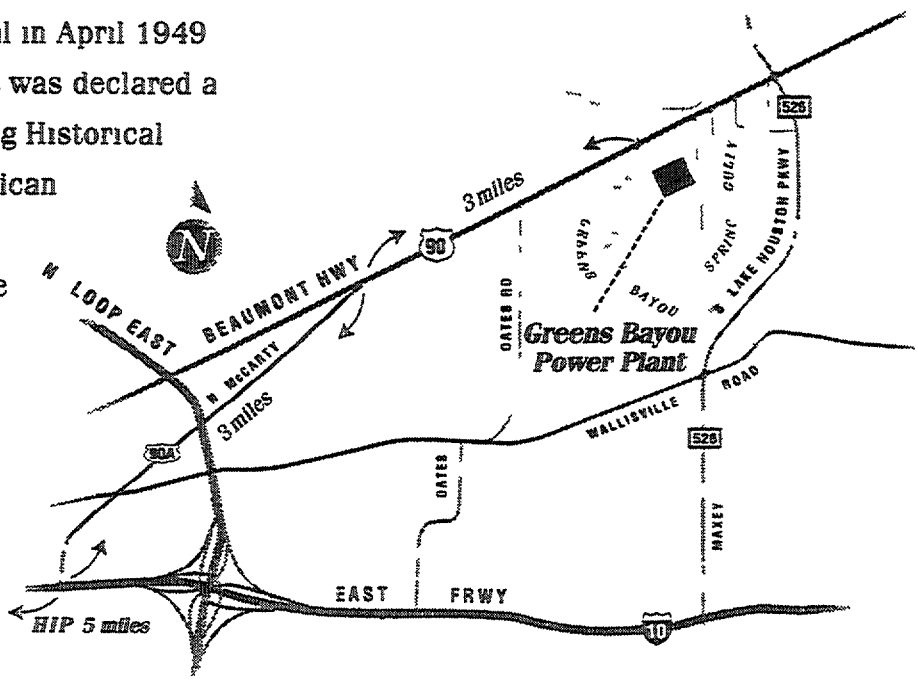
ELECTRIC GENERATING STATION

Plant Data

- The Greens Bayou Electric Generating Station is located on a 560 acre site in northeast Harris County just off Highway 90 (also known as the Old Beaumont Highway)
- The plant consists of one 425 MW steam unit and six simple cycle gas turbines The plant site also houses four retired steam units
- Unit 1 went commercial in April 1949 In June 1991, this unit was declared a Mechanical Engineering Historical Landmark by the American Society of Mechanical Engineers for being the first fully outdoor unit to operate in the United States
- The primary fuel for the plant is natural gas supplied by outside vendors Fuel oil serves as backup and is delivered to the plant by an inter-connected HL&P fuel oil pipeline, tank truck, or by rail

Cooling Water

- Cooling water makeup comes from Lake Houston via the Industrial Water Canal The water is pumped to the plant to a storage tank and distributed to a



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cooling tower and the north clarifier system Cooling water for auxiliary equipment is chiefly supplied from an auxiliary cooling tower which receives makeup mainly from the north clarifier with service water from the settling basin as a backup Three water wells supply makeup for the settling basin with two wells designated as backup for the potable water system Fire protection is provided from the auxiliary tower through an interconnected loop Potable water is supplied from an independent water well system for drinking/hygiene purposes

Pollution Control

- Five waste water containment ponds along the road entering the plant hold boiler blowdown water, demineralized waste water (along with septic treatment), organic, and ash wash (boiler chemical cleaning)
- An API oil separator traps, skims and stores waste oil that is later recycled or disposed of offsite

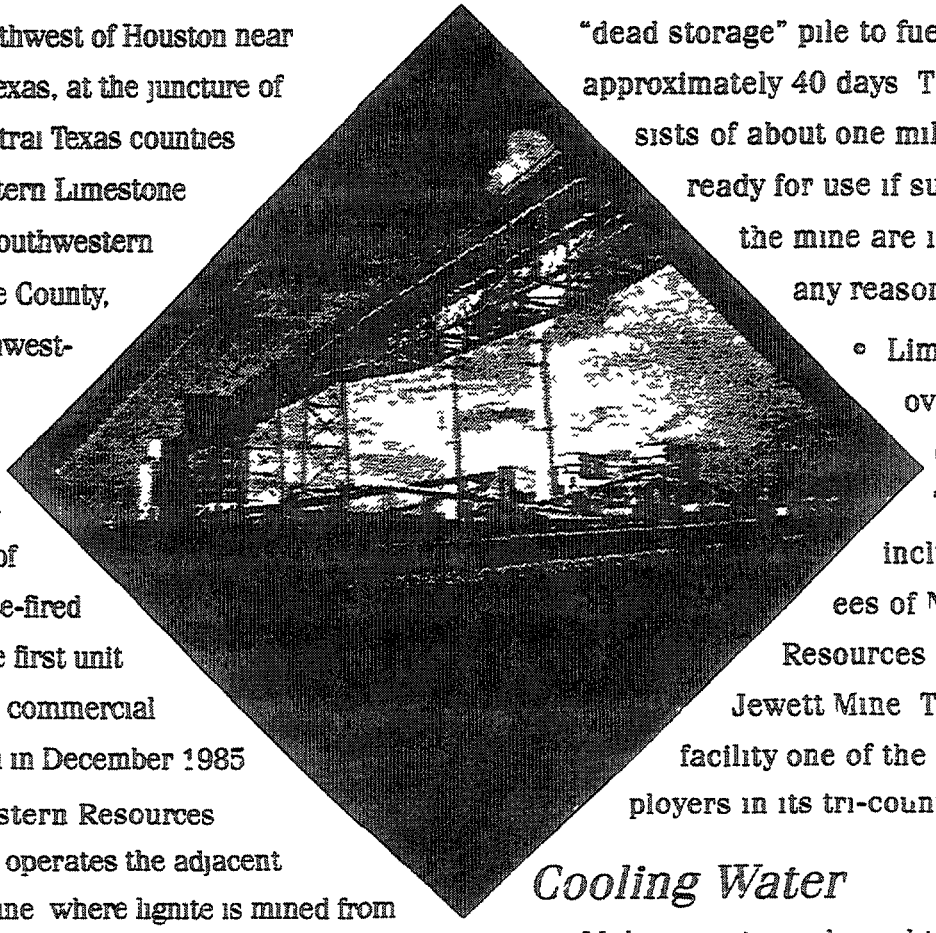
POWER PLANT SUMMARY

LIMESTONE

ELECTRIC GENERATING STATION

Plant Data

- The Limestone Electric Generating Station is located on a 3,800 acre site about 120 miles northwest of Houston near Jewett, Texas, at the juncture of three central Texas counties southeastern Limestone County, southwestern Freestone County, and northwestern Leon County
- The plant consists of two lignite-fired units The first unit went into commercial operation in December 1985
- Northwestern Resources Company operates the adjacent Jewett Mine where lignite is mined from several locations to fire the plants two units Combined the units consume about 25,000 tons of lignite each day — or about 8,000,000 tons per year
- Enough lignite is stored in the huge "dead storage" pile to fuel the plant for approximately 40 days The pile consists of about one million tons ready for use if supplies from the mine are interrupted for any reason
- Limestone has over 1 000 employees This number includes employees of Northwestern Resources Company's Jewett Mine This makes the facility one of the largest employers in its tri-county area



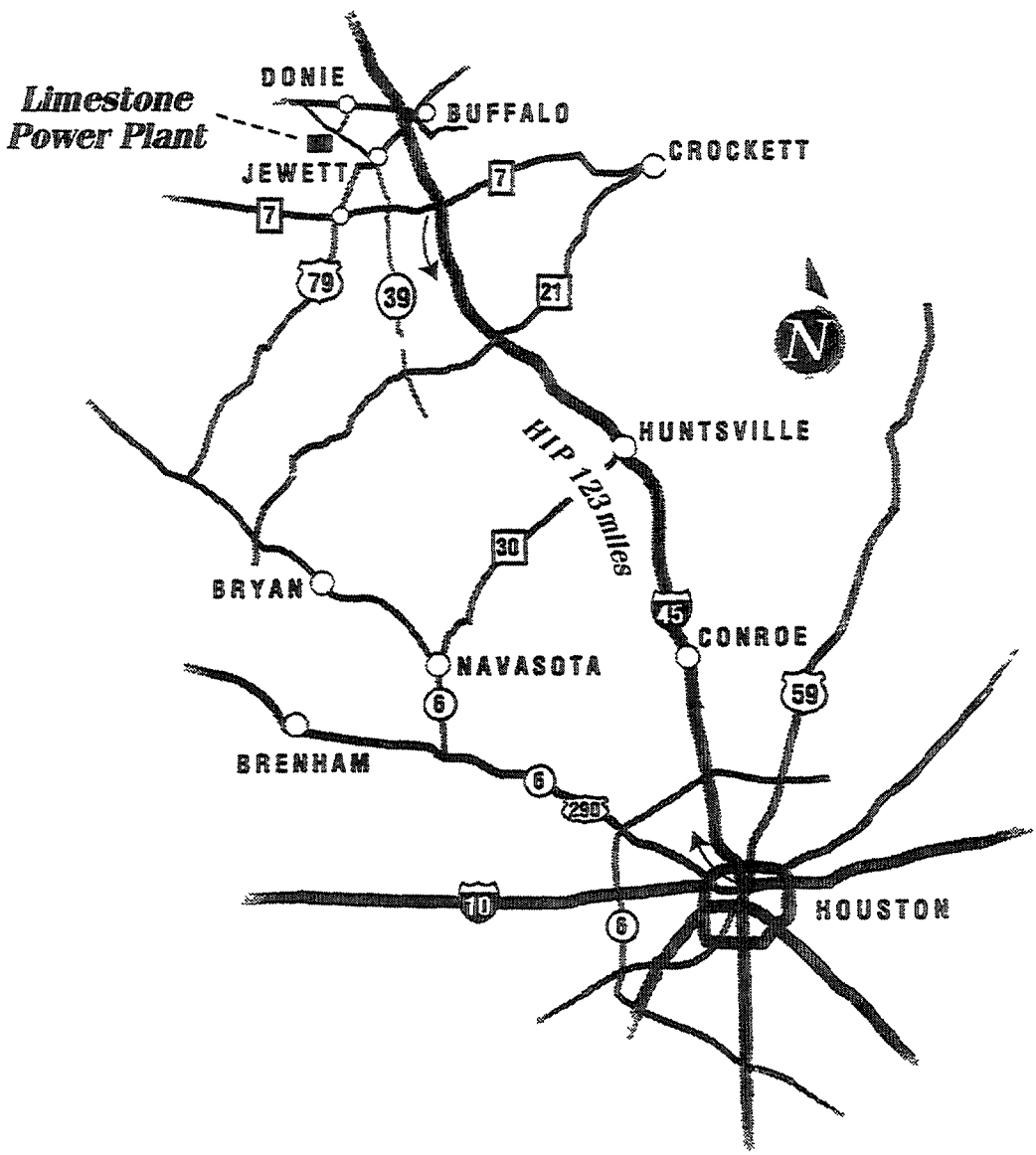
Cooling Water

- Makeup water is brought by pipeline from Lake Limestone, which lies just west of the plant Two closed-cycle

mecnanical draft cooling towers are capable of cooling about 260,000 gallons of water per minute Water temperatures averaging 120°F are lowered to about 95°F for reuse

Pollution Control

- The plant uses flue gas desulfurization or "scrubbers" to control sulfur dioxide emissions
- Precipitators control emissions of fly ash by trapping 99 8% of the fly ash
- Water is reused in plant systems to minimize discharges of wastewater
- Hazardous wastes are collected and disposed of offsite by a licensed contractor



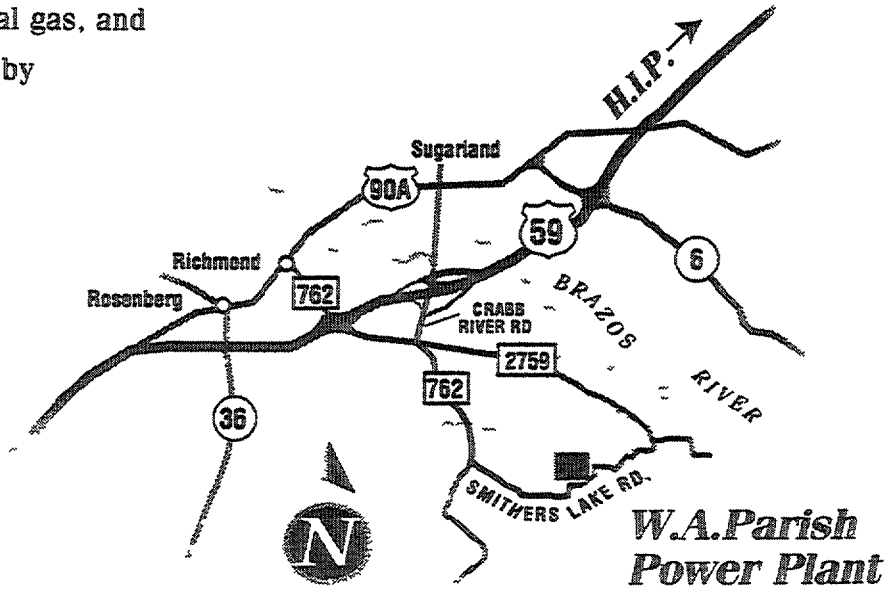
POWER PLANT SUMMARY

W.A. PARISH

ELECTRIC GENERATING STATION

Plant Data

- The W A Parish Electric Generating Station is located on a 4,900 acre site near the Brazos River in Fort Bend County The plant is about 10 miles south/southeast of Richmond/Rosenberg and 26 miles southwest of Houston
- This plant is the largest generator of electricity in HL&P's system It has eight generating units capable of producing 3 5 million kilowatts a day Four of the units use natural gas, and the other four are powered by low-sulfur Western coal
- Coal trains arrive at the plant daily to supply the four coal units These four units (Units 5 through 8) consume up to 34 320 tons of coal a day at full capacity The plant has the capability of storing approximately one million tons of coal on-site — this is about a 45-day supply
- Natural gas for the four gas units and one gas turbine is provided by outside vendors
- W A Parish has more than 500 employees on-site This makes the plant one of the largest employers and taxpayers in Fort Bend County

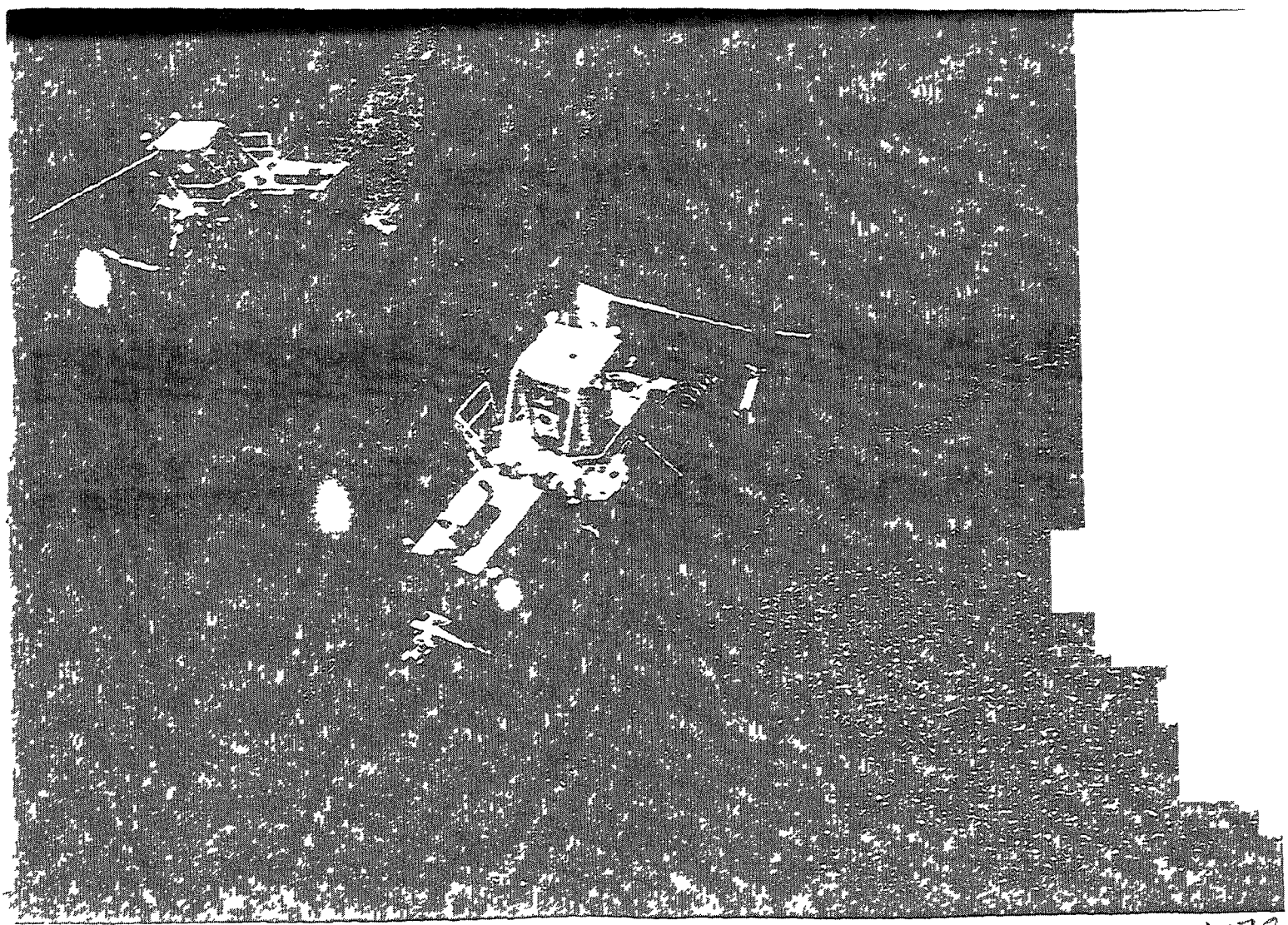


Cooling Water

- Smithers Lake is located on the northwestern portion of the plant property This 2,500 acre lake provides cooling water for plant Units 1 through 6 Makeup water is provided by natural rainfall and the Brazos River Unit 7 has an octagonal, mechanical induced draft counter-flow cooling tower Unit 8 has a circular mechanical induced draft, cross-flow cooling tower

Pollution Control

- A baghouse filtering system is used to remove the fly ash from the flue gases that are released from the stacks A scrubber system on Unit 8 removes sulfur oxides from the flue gases
- HL&P sells the ash created by burning coal for use in cement concrete blocks, road construction, marine reef substrate, and other products
- Hazardous wastes are collected and disposed of offsite by a licensed contractor



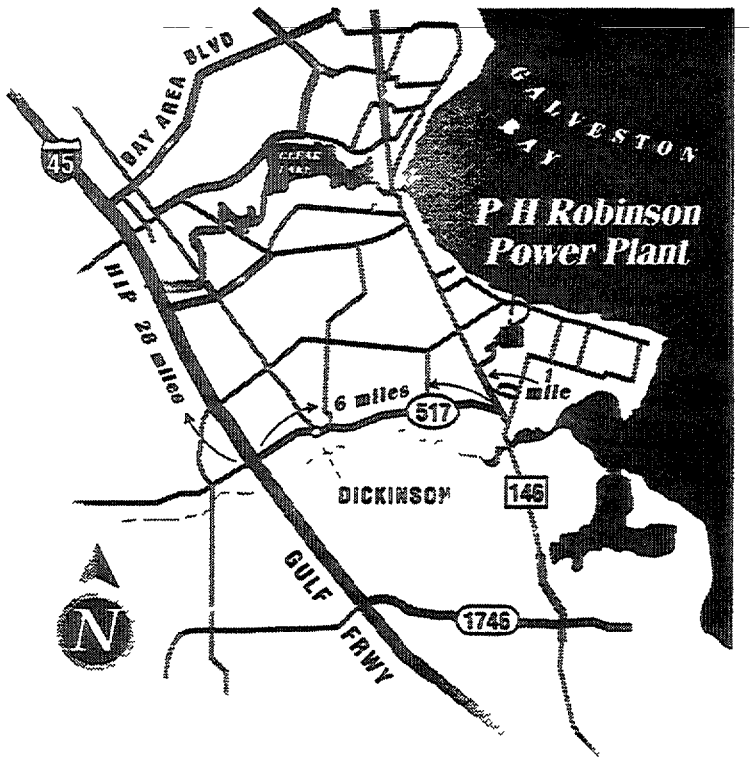
POWER PLANT SUMMARY

P.H. ROBINSON

ELECTRIC GENERATING STATION

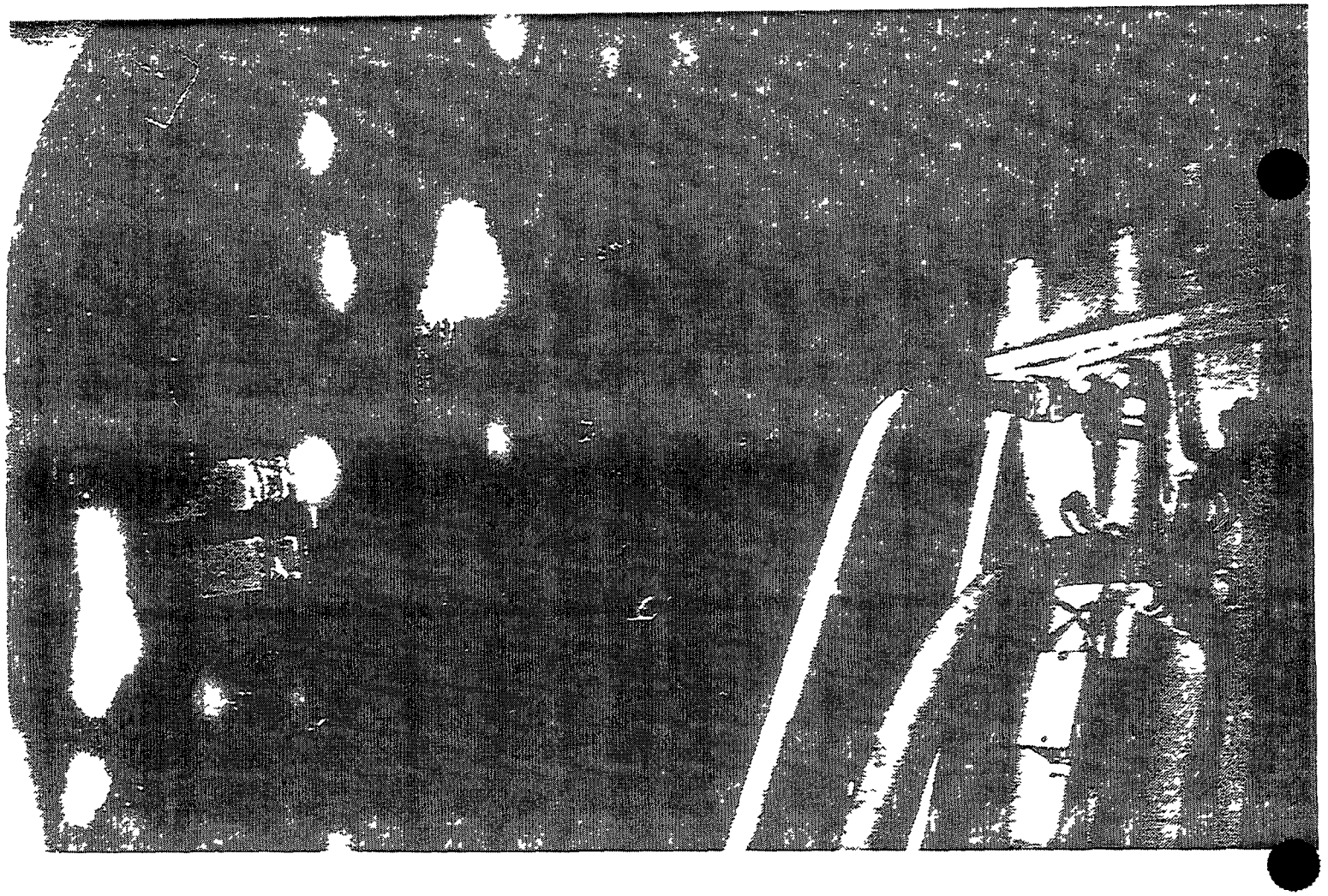
Plant Data

- P H Robinson plant is located on a 1,200 acre site east of San Leon, Texas, on Texas State Highway 146
- The plant consists of four steam generating units and began commercial operation on June 1, 1966
- Natural gas supplied by outside vendors is the primary fuel for all units An internal HL&P pipeline system can supply either fuel oil or natural gas to the plant Natural gas is injected into this pipeline from various suppliers along the pipeline route



Cooling Water

- Cooling water for the main condensers is obtained from Galveston Bay via an existing barge channel from Dickinson Bay through a 2 3 mile intake canal The discharge canal, which is approximately 2 miles long, enters Galveston Bay
- Surface water from the Galveston County Water Authority Distribution System is used for station service, steam generator makeup and cooling tower makeup Cooling towers are used for lube oil and hydrogen cooling systems Five deep wells are maintained to supply fresh water during surface water supply outages



ollution Control

- For protection against high tides during hurricanes, the entire plant island, including the switchyard, was elevated 8 feet above normal grade to a finished grade elevation of 18 5 feet above sea level The plant pavement is at elevation of 19 5 feet Fill to raise the grade level was obtained from excavation of the discharge canal A sub-surfa rainage system was installed under the fill and drains into the intake canal
- A side channel off the discharge canal feeds five supplemental cooling towers These cooling towers were installed to limit the average discharge temperature to less than 95°F
- Hazardous wastes are collected and disposed of offsite by a licensed contractor.

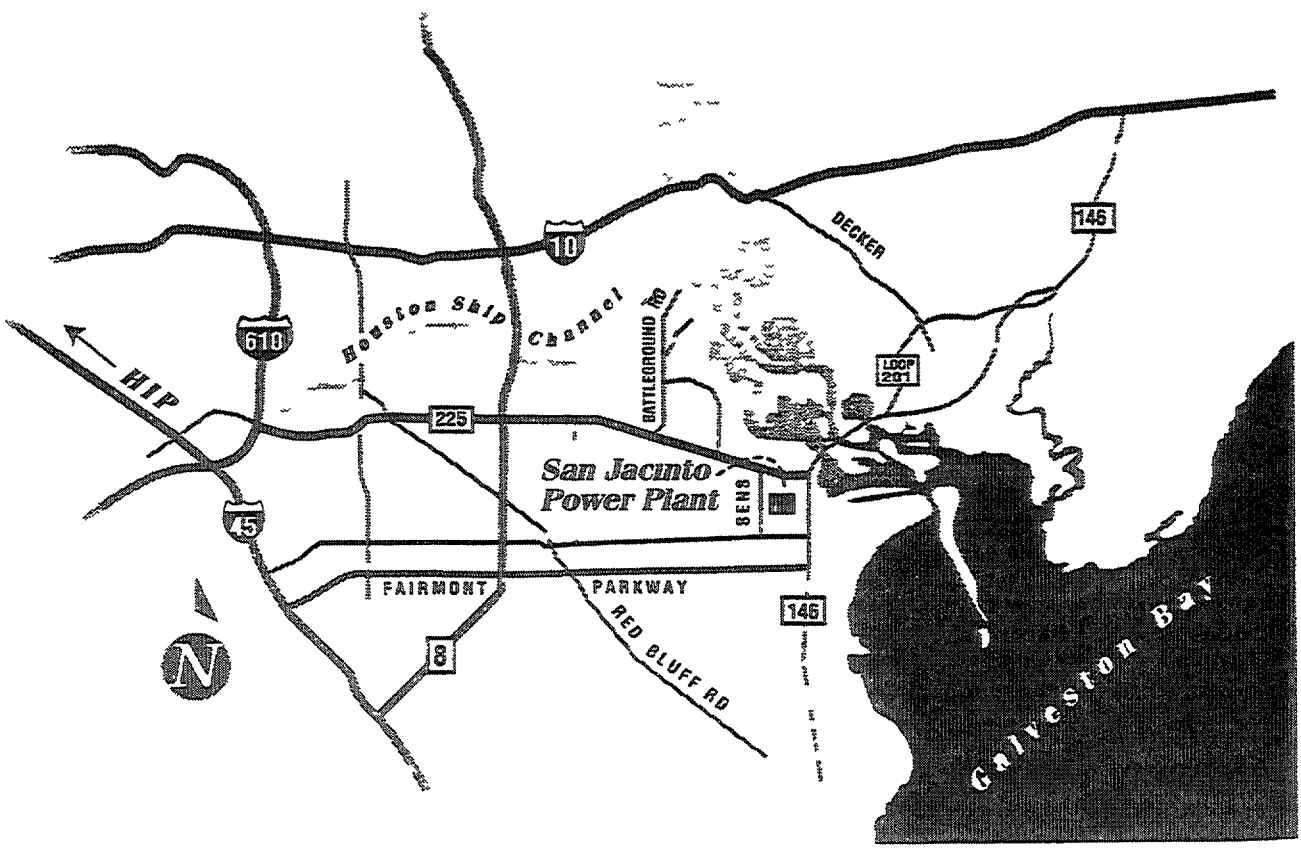
POWER PLANT SUMMARY

SAN JACINTO

STEAM ELECTRIC STATION

Plant Data

- The San Jacinto Steam Electric Station is a cooperative effort between HL&P and the E I du Pont de Nemours Company (DuPont)
- The plant is located on a 10 acre site on Sens Road southeast of the San Jacinto Monument (adjacent to DuPont's chemical complex on the Houston Ship Channel)
- The plant consists of two gas-fired combustion turbine generators and two heat recovery steam generators (HRSG)
- The San Jacinto Station produces steam, which is sold to DuPont, and electricity, which is distributed to HL&P's customers With this cogeneration plant, HL&P enters a new era in



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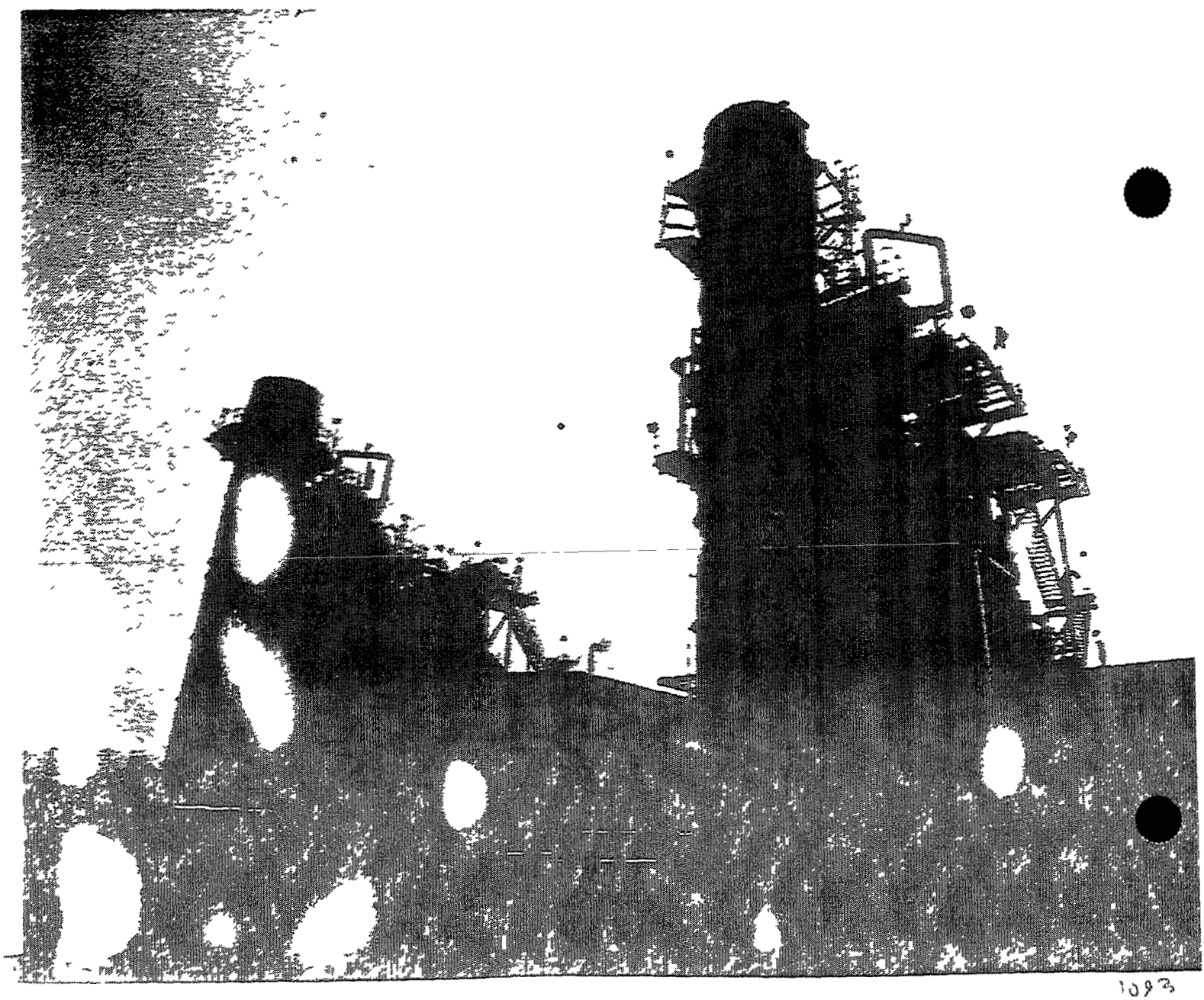
elect c generat nall ighly efficient plants using state-of-the-art technology This plant is unique since it is the first utility-owned cogeneration project i e state and one of the few in the ation

Cooling Water

- The p'ant has a se. ontained water-glyc oling water system consisting of e ans and three pumps
- Makeup water is obtained from DuPont and condensate is returned to the San Jacinto Steam Electric Station

Pollution Control

- The plant uses specially designed combustors which limit emissions of oxides of nitrogen
- Plant waste waters are treated by DuPont's treatment processes prior to discharge



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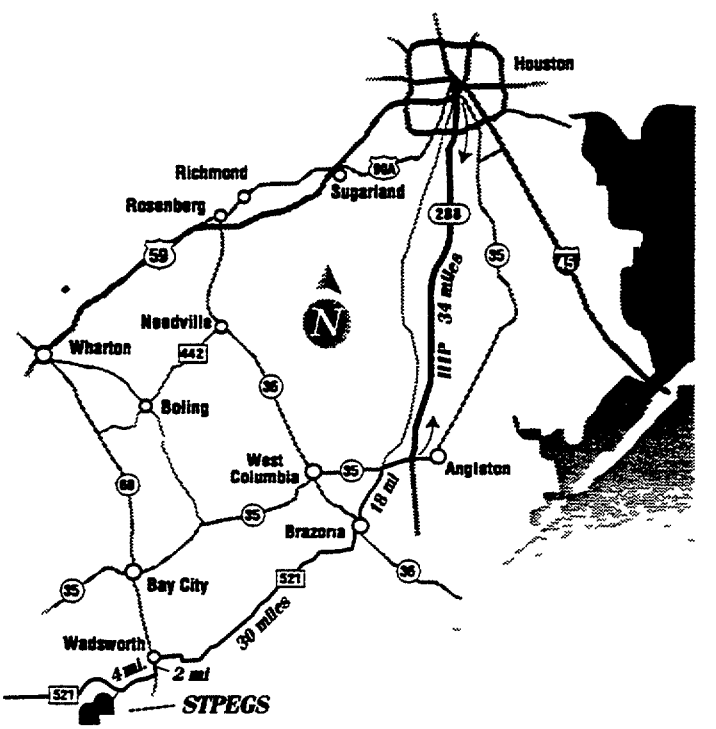
POWER PLANT SUMMARY

SOUTH TEXAS PROJECT

ELECTRIC GENERATING STATION

Plant Data

- The South Texas Project (STP) is located on a 12,200 acre site on the Colorado River in Matagorda County, Texas, between Bay City and Palacios The plant began commercial operation in August of 1988
- The plant consists of two units Each unit houses a 1,250 MW Westinghouse Electric Corporation pressurized water reactor These two reactors are the largest electric generating units in Texas and are among the largest in the nation Every year, the two units generate the energy equivalent of 25 million barrels of imported oil or 142 billion cubic feet of natural gas
- Each reactor houses 193 fuel assemblies A fuel assembly consists of 264 fuel rods approximately 14 feet in length A single rod contains more than 300 uranium dioxide pellets One fuel assembly costs approximately $400,000, however it can supply the energy equivalent of more than $4 million worth of oil
- About one-third of the plant's fuel rods are replaced every 18 months Ultimately, spent fuel rods are sent to U S Government depositories However, STP has enough space to store spent fuel rods in on-site underwater storage pools for the entire licensed operating life of the plant



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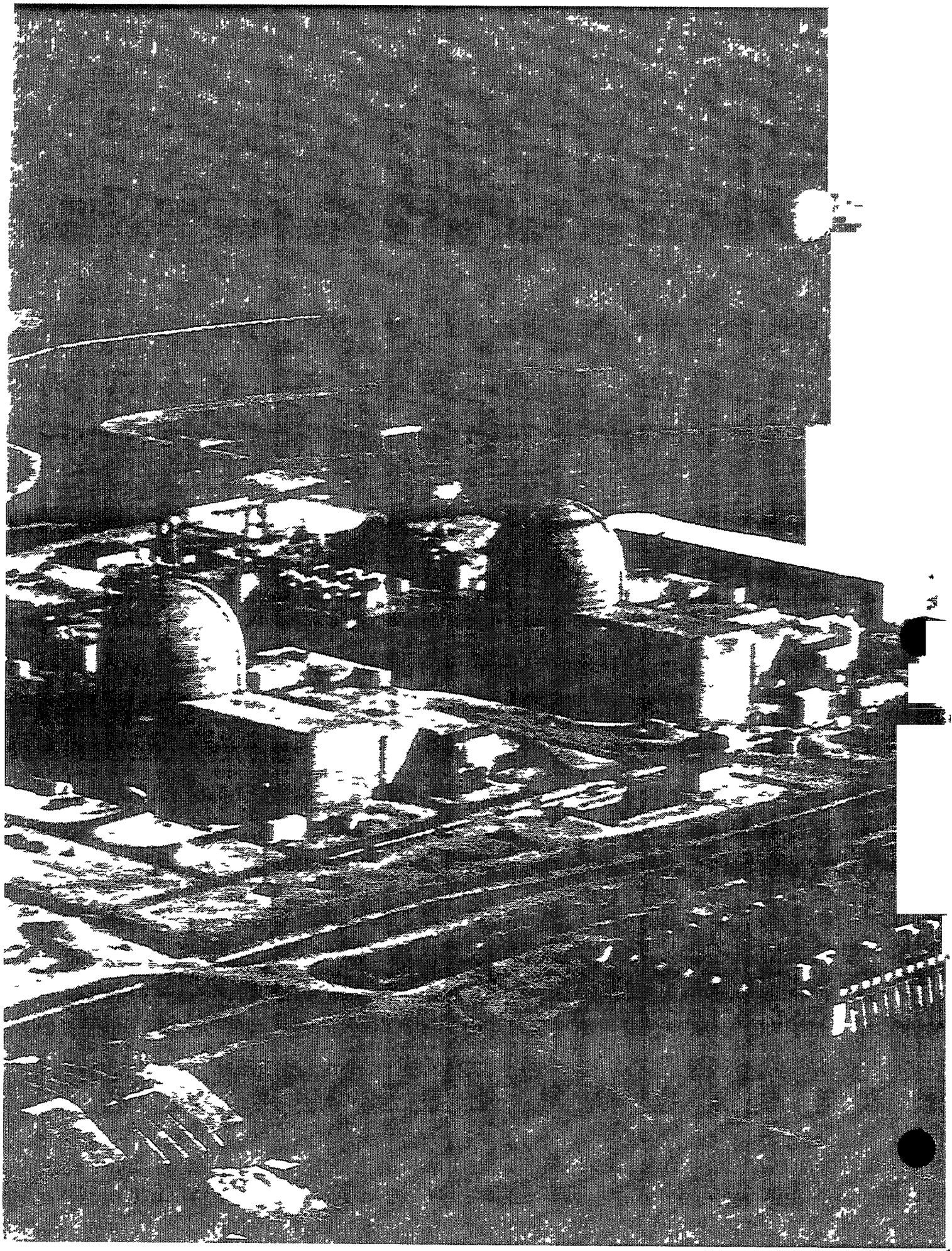


- Houston Lighting & Power Company owns 30 8% of the project and is the managing owner City Public Service of San Antonio owns 28%, Central Power & Light Company owns 25 2%, and the City of Austin owns 16%
- Including contract labor, there are over 2,000 employees on the site This makes STP the largest employer and taxpayer in Matagorda County

Cooling Water

- Cooling water is obtained from a 7,000 acre reservoir located on the plant site This is one of the largest above-ground reservoirs in the world

Safety Features

- STP is the only plant in the country to have three independent and redundant safety systems controlling reactor operations All other plants have two Barriers to protect against the release of radioactive materials include the 4-foot thick steel-reinforced concrete reactor containment buildings and their 18-foot thick concrete and steel foundations
- The plant has become a model of the best in nuclear technology and safety, attracting visitors from as far away as Japan, China, France, and the former Soviet Union STP was selected by the Nuclear Regulatory Commission as the plant of reference in a U S /Soviet Nuclear Safety Information Exchange prior to the breakup of the former Soviet Union

Emergency Plan

- STP's emergency plan was developed according to Federal Regulations An STP Emergency Response Team participates in periodic emergency drills with federal, state, and local officials
- Residents living within 10 miles of the plant are notified of any emergency by 12 warning sirens, tone alert radios, and a computerized telephone calling system provided and maintained by the plant The notification system is activated by county officials to broadcast emergency information on nuclear matters as well as any other kind of emergency

Wildlife

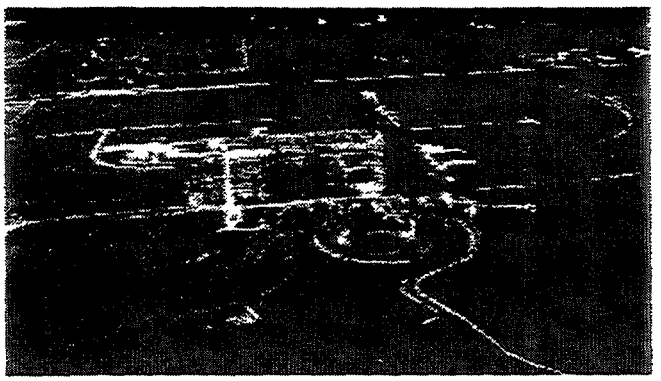
- The STP plant site has been declared a wildlife sanctuary and the alligator has become the plant's unofficial mascot Approximately 50 of the reptiles live and feed around the above-ground reservoir In addition to the alligator the acreage around the plant is home to other wildlife including the white-tailed deer and over a hundred species of birds Many of the birds that occasionally visit the site are on Texas' threatened/endangered species list

WEBSTER

GENERATING STATION

Location

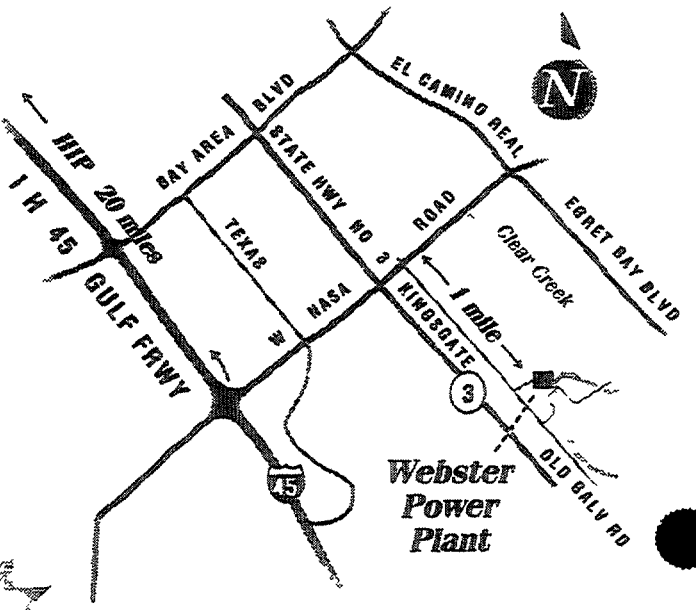
- The plant is located on a 700 acre site southeast of Houston on Texas State Highway 3 between the towns of Webster and League City The plant began commercial operation on June 1, 1954



- The plant consists of one active steam generating unit and one gas turbine generating unit *(Note The plant site also houses two decommissioned steam generating units)*
- Fuel for the plant is natural gas supplied by outside vendors An internal HL&P pipeline system crosses the plant site and is connected to a plant natural gas metering station Natural gas is injected into this pipeline from various suppliers

Cooling Water

- Cooling water for the main condensers is obtained from Clear Creek through a 0 7 mile intake canal which is 13 feet deep and 30 feet wide at the bottom The cooling water is discharged into Clear Lake through two canals
- Surface water from the city of Webster's distribution system is used for station service steam generator makeup and cooling tower makeup Cooling towers are used for lube oil and hydrogen cooling systems Two deep wells are maintained to supply fresh water during surface water supply outages



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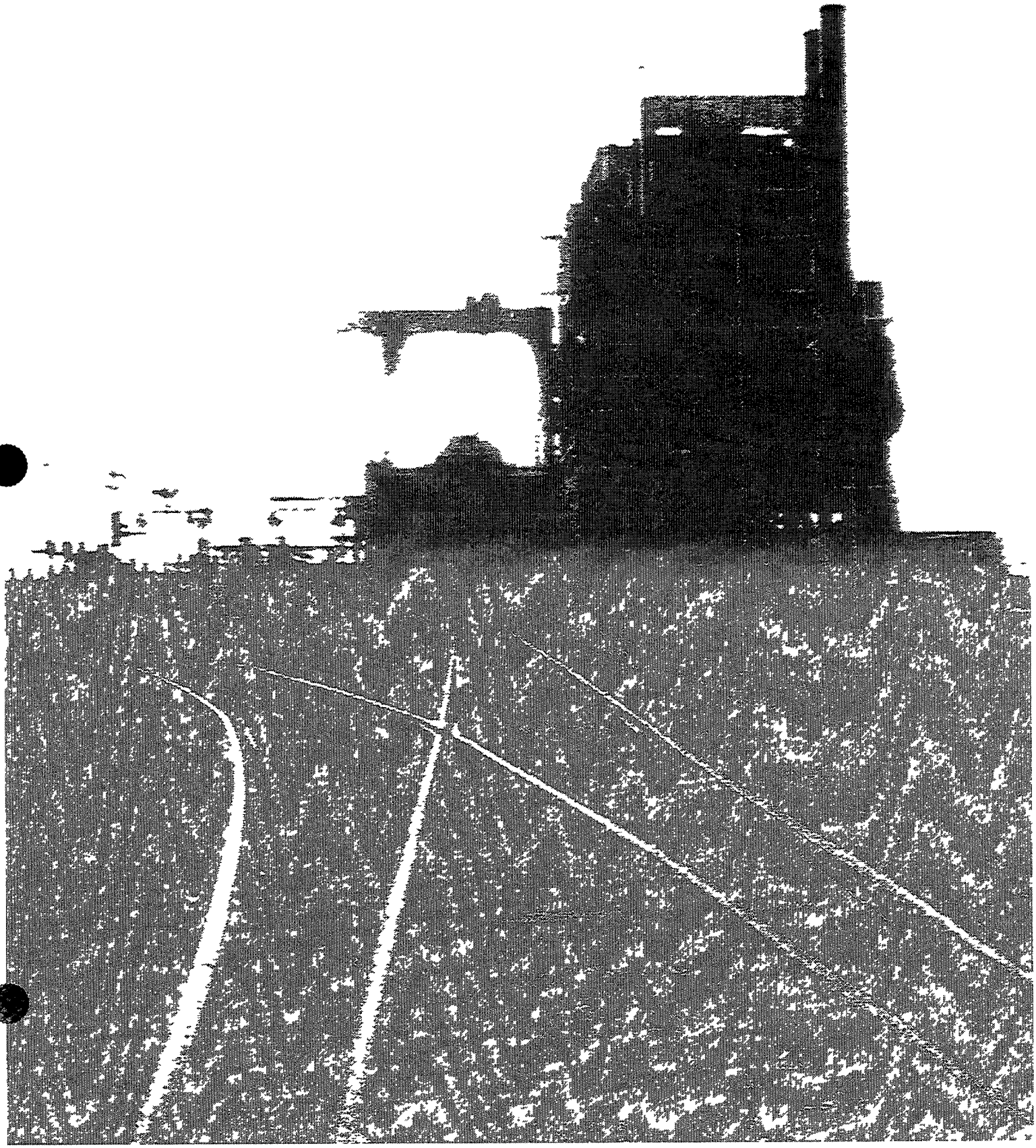


POWER PLANT SUMMARY

T.H. WHARTON

GENERATING STATION

Plant Data

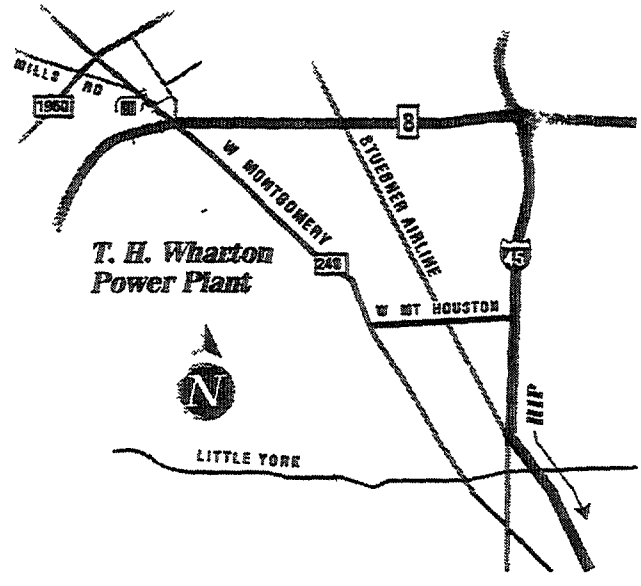
- The T H Wharton Generating Station is located on a 600 acre site approximately 20 miles northwest of Houston on FM Road 249 T H Wharton began commercial operation on July 1, 1958
- The plant consists of 18 electric generating units These units feed electrical power into the north and west portion of HL&P's transmission grid
- The primary fuel for this plant is natural gas supplied by outside vendors Fuel oil serves as standby

Cooling Water

- Fresh water from eight deep wells is used for station service, boiler make up, and cooling tower makeup Cooling water for main condenser service is obtained from cooling towers These cooling towers receive warm water from steam condensers, cool it approximately 15°F and return it to the unit condensers

Pollution Control

- The plant maintains an API separator in series with a tricellerator to eliminate oil from wastewater Other wastewater streams (boiler blowdown, demineralizer regenerant wastes etc) are routed to a concrete lined holding sump to be treated by the chemical waste system All hazardous materials are stored in an approved building (no more than 90 days) before being shipped out for proper disposal



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OUTAGES

"When the Lights Go Out"

Undervoltage irregularities (lights out) include voltage notches, voltage sags, and outages These irregularities are characterized by their duration and magnitude

- **Voltage notches** usually last less than 0 01 seconds and are characterized by a momentary loss of power Voltage notches can be caused by starting loads, utility switching, or equipment failure
- **Voltage sags** usually last longer than 0 01 seconds and are characterized by voltages up to 20% below the normal service voltage Sags may be caused by system overload, starting very large loads, utility switching, equipment failure, or lightning
- **Outages** last longer than 0 10 seconds and are characterized by a total loss of power Outages can result from natural disasters accidents equipment failure or a short circuit in any part of an electrical system

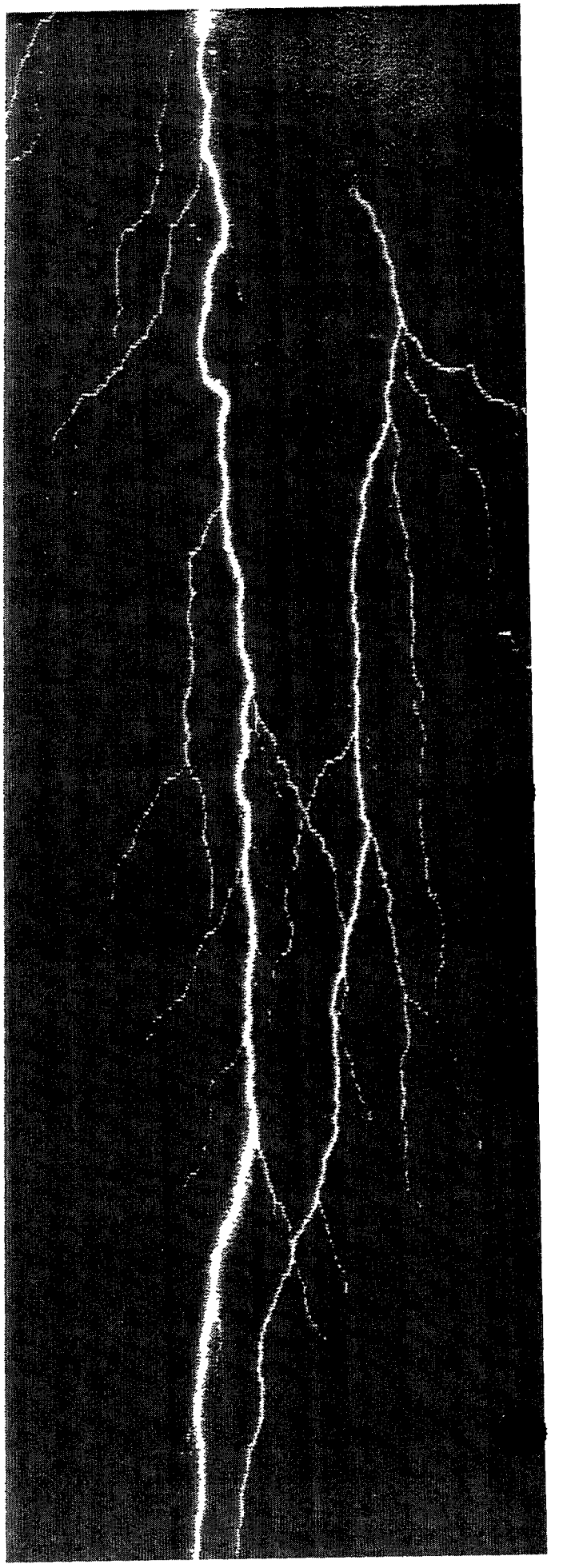
HL&P's customers play a key role during power outages and emergency situations Their calls help us to evaluate the extent of service outages, the locations of the outages, and any electrical hazards that may exist

To report power outages, customers can call HL&P 24 hours-a-day, 7 days-a-week and follow the simple instructions provided by the Easy Access Network Once notified of a power outage or emergency situation HL&P puts all available personnel and equipment into service

Following severe storms or other significant power outages, HL&P's PowerCall System places a call-back to each customer who telephoned to report lights out and requested a return call to verify restored service This computerized system helps to rapidly locate specific problem areas that still need attention Repair crews are then dispatched to these areas to complete the needed repairs

PowerCall handles the call-back with an automated voice message system asking if service has been restored. The voice will say *"Hello, this is the Light Company calling. Our records show that service in your neighborhood has been restored. Our reason for calling is to identify those isolated cases where electricity is still off."* The customer is then prompted to respond using the telephone touchpad, or if they have a rotary phone, their voice. PowerCall will say *"If your electricity is back on, please press **one** now or say the word **one**." If the electricity is still off, the customer is asked to press or say **two**.*

If the electricity is still off, PowerCall re-dispatches repair crews to the neighborhood to restore service.



ENERGY CONTROL AND DISPATCHING

Dispatching

To regulate the amount of power generated and control its distribution, HL&P operates the Energy Control and Data Center (EC/DC) The EC/DC is the nerve center of HL&P operations Fuel costs, weather conditions, and generation load balance are all monitored at the EC/DC Since electricity is delivered to the customer as it's generated forecasting and continual tracking are essential

The Energy Control Department is responsible for the generation, transmission, and substation systems Energy Control personnel operate a sophisticated, state-of-the-art computer system called the Energy Management and Control System (EMACS)

EMACS automatically selects the most cost-efficient combination of generating units to meet the area's energy needs Load forecasting is performed to predict power requirements on a daily weekly, and monthly basis Using this data and a model of the power system generating units are operated efficiently and at the lowest cost possible Each generator is reexamined every two seconds and its output raised or lowered automatically to achieve the most economical cost This includes minimizing fuel costs and the purchase or sale of power from various entities, including other utilities and cogenerators

EMACS also tracks the flow of electricity through more than 35,000 miles of transmission and distribution lines

Because Energy Control maintains a 24-hour watch over operations, it also coordinates System Dispatching System Dispatching is responsible for the integrity of the transmission system — everything from the power plant transformer to the substation

Computers located at all substations power plants and fuel delivery sites report the status of over 50 000 points at intervals from two seconds to one minute back to the EMACS The status or value of the points

reported ranges from the open/close status of circuit breakers and switches to the power flows on all HL&P cir The EMACS simultaneously mode e pc system and continuously runs security programs to automatically detect potential problems in advance This information is used to instantly determine any pr ems occurring in the system In response to alarms or indicat the dispatchers can take remote cor e action or dispatch crews

While System Dispatching monitors the transmission system, Zone Dispatching is charged with ensuring the integr nd re l- ity of the distribution circuits to customers Zone Dispatching maintains HL&P's distribution system — all the power lines from the substation to the customer

Because of HL&P's vast distribution network, dispatching operations are divided into four zones Dispatching for the North and East Zones is located at the Greenspoint District Office Dispatching for the South and West Zones is located at the South Houston Complex

Zone dispatchers are the ones who respond to customer service calls

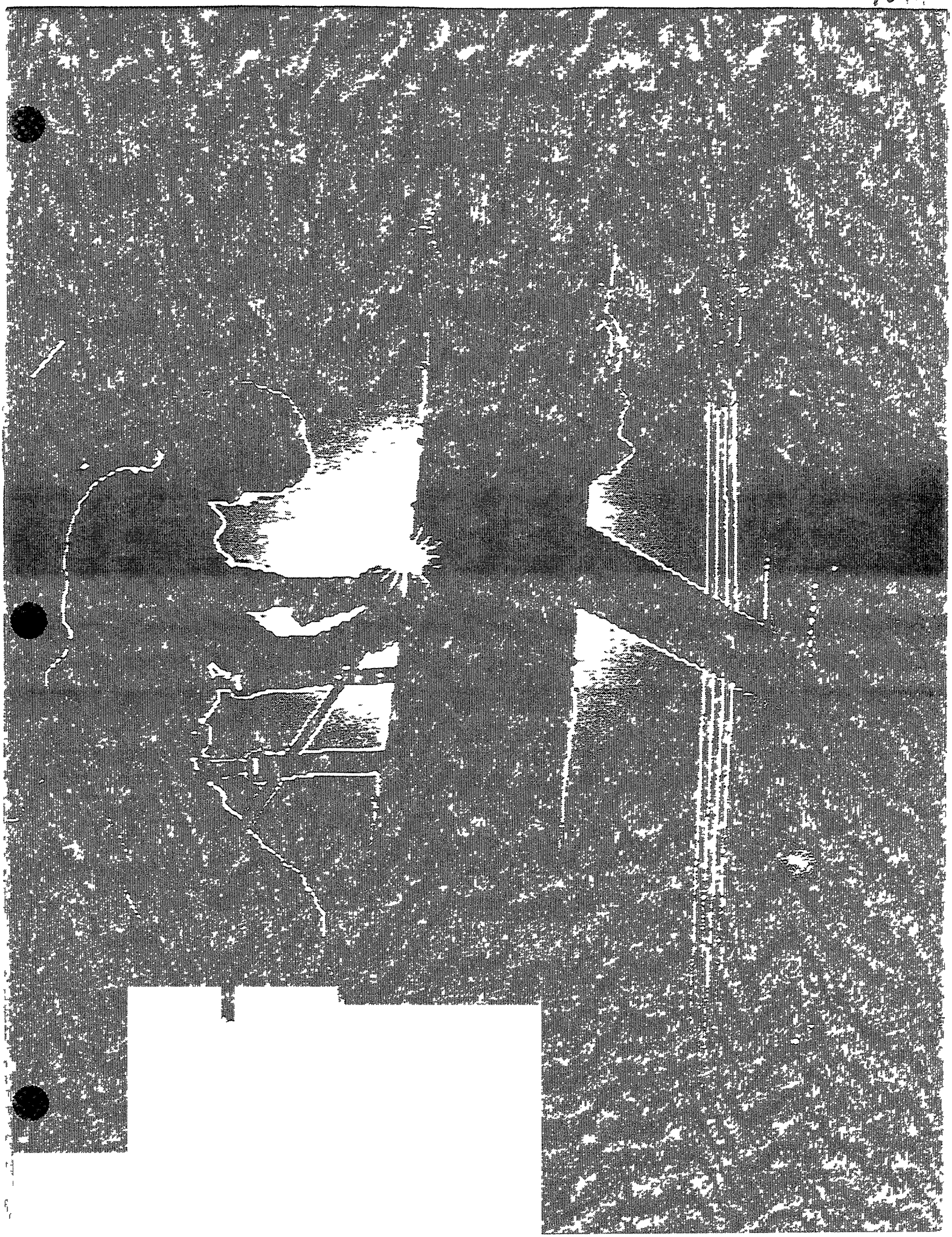
When a customer calls to report a power outage, the information is entered into a computer and a repair order is generated The order lists the customer's address and nearest distribution circuits If more than one customer calls with the same problem the computer's Outage Analysis stem can often pinpoint the problem

Zone dispatchers are connected to EMACS computer terminals The EMACS maintains an extensive map which replicates exactly what's in the field right down to switches and breakers Based on the repair location, dispatchers determine which crew to assign When the damage has been assessed dispatchers issue switching orders and clearances to disconnect power to the affected line Safety is the main concern

But the job is not complete until the crew reports exactly what repairs were made The dispatcher enters this into the computer to keep track of repairs and let Customer Service know the problem has been fixed

The Zone Dispatching offices also handle the maintenance of outage databases and the location of all critical customers (Critical customers such as kidney dialysis, heart patients, etc , are identified by their doctors as having the need for quick response in repairing interruption in electrical service)

Note EMACS computer terminals are also located at other Electric Reliability Council of Texas (ERCOT) utilities to enable the rapid access and sharing of information to optimally operate the HL&P power system



CREWS

AND LINE WORK

Typically, repair crews are dispatched from HL&P Service Centers These local centers serve as home base to Transmission and Distr[illegible]tion crews

To ensure ma[illegible]enance and repair crews get into the field as quickly as possible, Service Centers warehouse commonly needed parts — b[illegible]akers, sv[illegible]hes, po[illegible] and power lines — a[illegible]ell as a [illegible] of ser[illegible] trucks

Some jobs are small, while others are big, and repair crews vary in size, depending on th[illegible]pe of the repa[illegible]

S[illegible]ce crews are [illegible]rally comprised [illegible] one or two line mechani[illegible] Distribution crews in[illegible]e one to five persons The smaller crews repair problems such a[illegible]vned service drops, re-[illegible]g trans[illegible]rs, and line fuses They a[illegible]rform [illegible]ning o[illegible]tions The larger crews generally perform more intense work such as new construction (e g , sett[illegible]pole[illegible]nstalling new conductors, etc) [illegible]bor intensive repair work These crew[illegible] line trucks (these trucks generally have a hydraulic boom) or bucket trucks

Transmission crews generally contain three to seven persons The bucket trucks and the Condor (140 foot and 160 foot work platforms) have a crew of three The rest of the crews have seven persons Transmission cr[illegible]v trucks are generally readily identifiable by their heavy-duty appearance and four wheel drive for right-of-way use

Distribution crews perform their own switching by operating line switches with orders from the Zone Dispatcher However, Transmission crews have all their switching done by Substatic[illegible]perations because of (1) proximity — [illegible]ations may be from 5 to 150 miles apart, and (2) quantity — there may be 7 or 8 substations on a line that is involved in the switching

Grounding is a procedure used by both Distribution and Transmission crews Grounds are conductors which are mechanically attached between phases and to ground with[illegible] hot stick after the line has been swit[illegible]ed out. A grounded line allows workers to work safer and faster than adhering to live line practices

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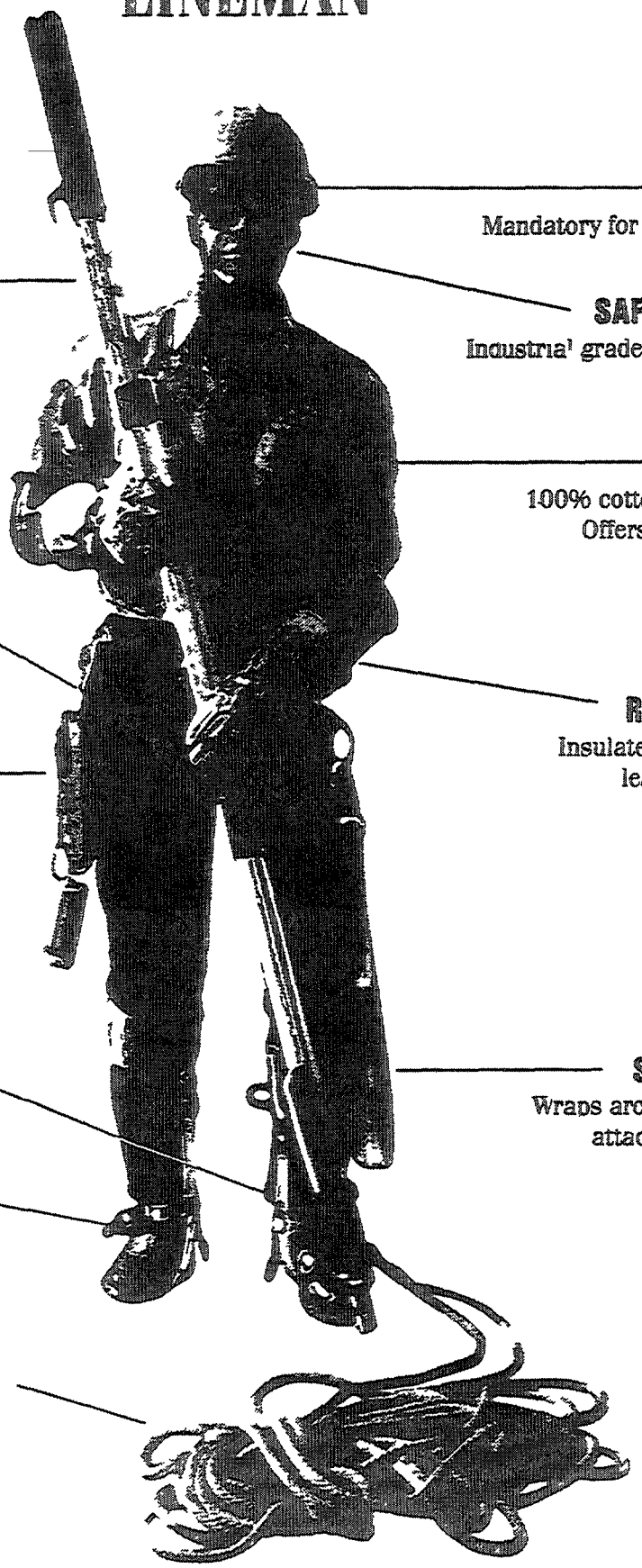
LINEMAN



HOT STICK
Eight-foot long fiberglass tool safely extends reach while working on energized lines

BODY BELT
Secures position on pole allowing free use of hands

TOOL POUCH
Used to hold hand tools

CLIMBERS/HOOKS
For climbing wood structures and getting into proper work position

CLIMBING BOOT
Protects feet from injury

HAND LINE
After materials are loaded into the tool bag this is used to pull them aloft

HARDHAT
Mandatory for head protection

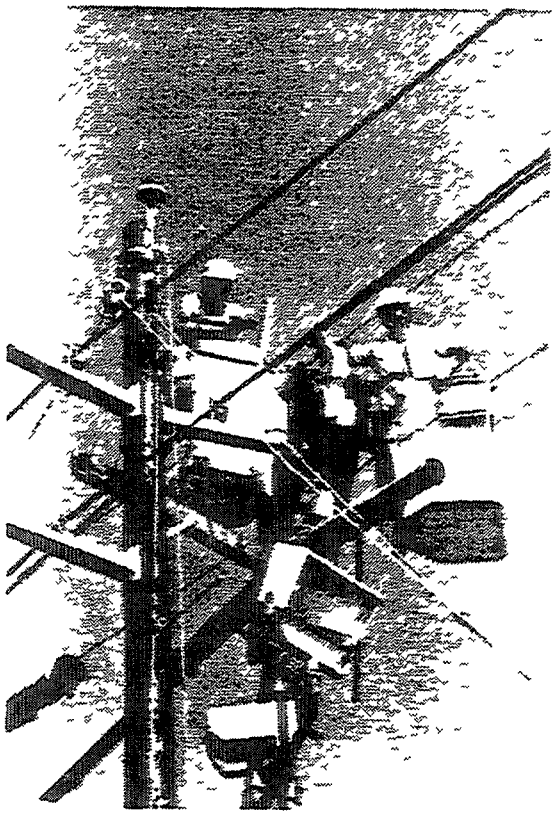
SAFETY GLASSES
Industrial grade glass or plastic

SHIRT
100% cotton long-sleeved
Offers protection from flash burns

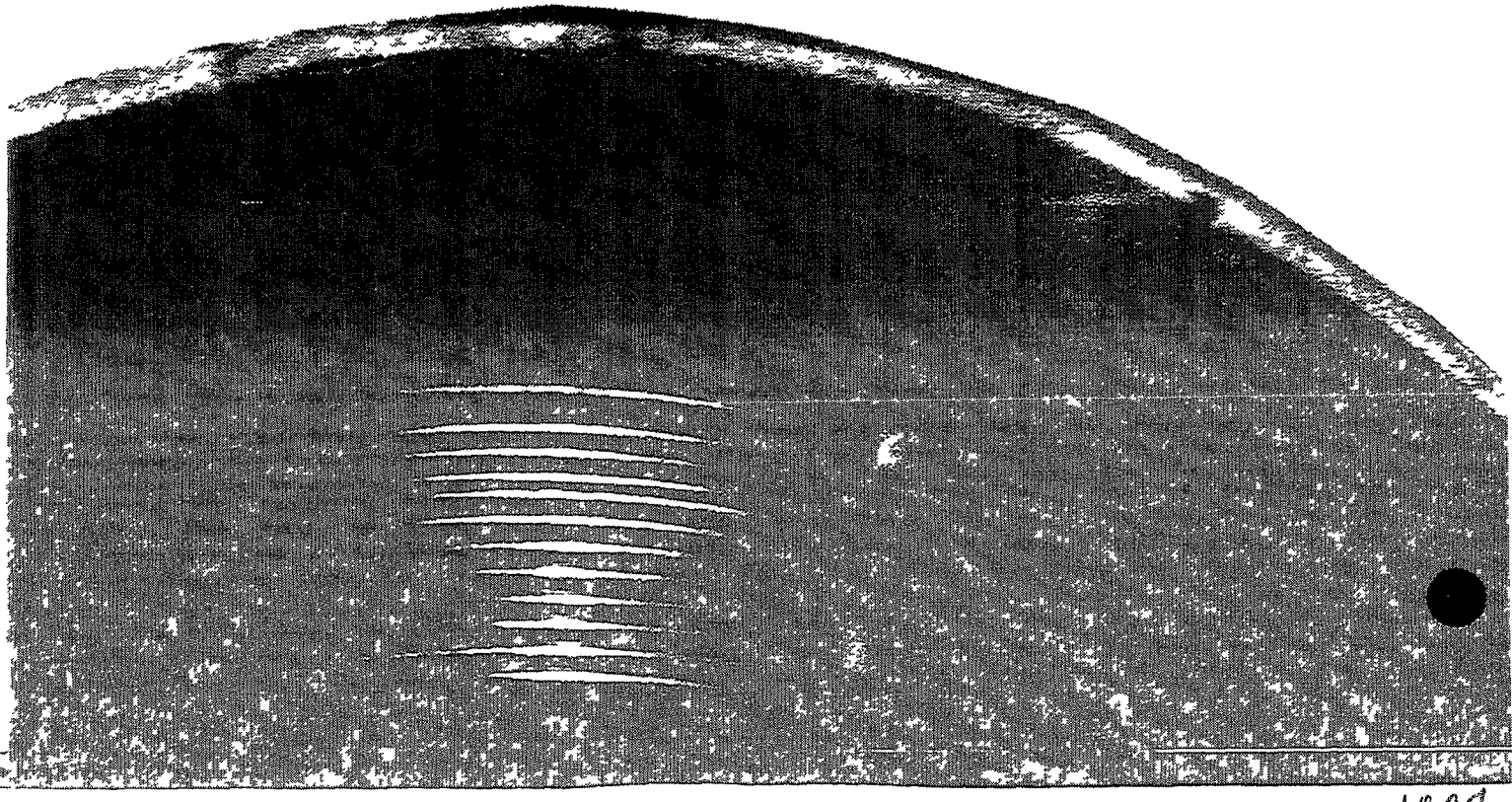
RUBBER GLOVE
Insulated and fitted with leather protectors

SAFETY STRAP
Wraps around the pole and attaches to body belt

Hot or live line work is done predominantly in Distribution. Distribution personnel work voltages up to 4,100 volts off the pole with rubber gloves. Voltages up to 15,000 volts may be worked out of a bucket truck with rubber gloves. Any voltages higher than that are done with hot sticks. Transmission crews have the capability of working 69,000 to 345,000 volts with hot sticks. This is only done when there are no alternatives. The reason Transmission can work higher voltages than Distribution is that transmission facilites have larger clearances between phases.



The Company makes every effort to dispatch repair crews in an expeditious manner. The target response time for crews to repair a "Lights Out Order" under normal circumstances is approximately four hours or less. However, often this target will not be met due to the extent of the damage and the repairs needed, the fact that some areas are not accessible for repair crews, or because the system has sustained severe damage due to weather conditions.



METERING

A watt (W) is a measure of the amount of work electricity can do Electrical appliances light bulbs, and motors have certain watt requirements depending on the task they are expected to perform

Electric energy consumption is measured in units called kilowatt-hours (kWh) A kWh is equal to 1,000 W of electricity used for one hour For example, a 100 W light bulb left on for ten hours uses one kWh of electricity A typical residential customer uses about 12,000 kWh during the year

The device that measures and records electricity usage each month is called a meter The two types of electric meters used most often by HL&P are (1) a kWh meter (used primarily for residential accounts) or (2) an indicating demand or kilovolt-ampere (kVA) meter (used primarily for commercial customers)

All electric meters have a name plate on the front The information on the lower half of the plate describes the characteristics of the meter type of meter, number of amps number of wires in service, and the voltage of the meter The meter serial number is assigned and printed in large figures by the manufacturer The serial number is referred to as the meter number and is used to identify the meter The meter is installed in a meter base located between HL&P's electric lines and the customer's wiring The meter registers the amount of electric energy that passes through it This electric energy turns the meter disc which is attached to gears The gears are connected to and turn the dials This is how the customer's use of electricity is recorded as kWh on the dials In our meter shop, HL&P calibrates and tests the meters to make sure they register accurately Each year we test a sampling of 1% of all our commercial and residential meters The meters are calibrated to be accurate within 1/2 of 1%

METER READING

Meters are read every month by HL&P Meter Readers The Meter Readers make their rounds with hand-held computers which have streamlined the meter reading and billing process

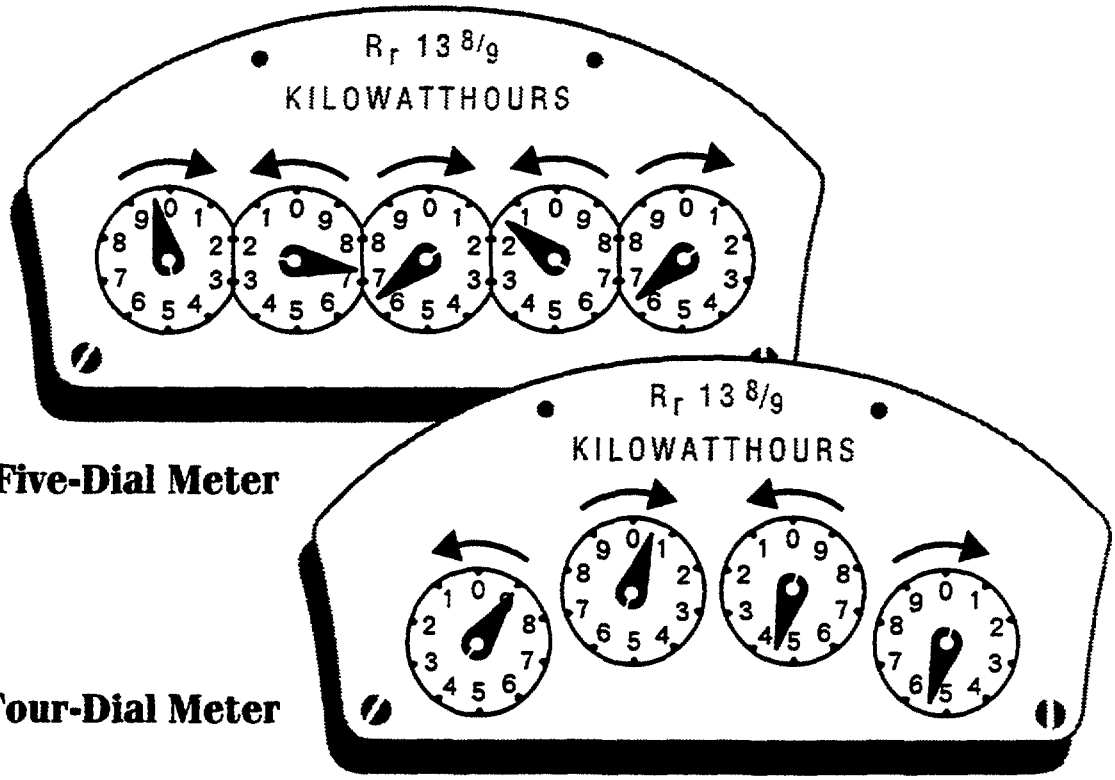
These computers have an accuracy rate of 99 9% Still, if customers want to monitor the amount of electricity they are consuming through the course of the month they are welcome to read their own meters By reading their own meters periodically, customers can make adjustments on how much electricity they are using This can help prevent surprises on their monthly electric bill

Learning how to read a meter is easy HL&P sends a complete set of instructions to customers along with examples to follow

All electric meters have dials Some meters have four dials, while others have five Both dial types are read the same way Before beginning, customers are asked to note that some of the hands on the dials turn clockwise and others turn counterclockwise

To read a meter, read each dial separately beginning with the dial on the left Each dial will have a hand or pointer If the pointer is between two numbers write down the number that the pointer has just passed (the lower number)

When the pointer on the dial seems to be exactly on the number check the next dial to the right If the pointer on that adjacent dial has passed zero that indicates the dial has made a complete revolution and you can write down the number the pointer is on If it has not passed zero, record the next lowest number to the pointer



Five-Dial Meter

Four-Dial Meter

Four-dial meters may be set to record a percentage of the electricity customers use (usually 10%) If so, the meter will have a multiplying factor printed on the meter below the dials, such as "multiply by 10" or "10x " If a customer has this type of meter, they need just add a zero to the end of the meter reading to get the actual number of kWh used

Five-dial meters do not use this multiplying factor and the reading will be exactly as the dials indicate

Just For Practice

Look at the illustrations and try the readings Start with the four-dial illustrations first The pointer on the first dial is right on the 9 Check the dial to the right It has passed 0, so the first dial reading is 9 The pointer on the second dial is between 0 and 1, so record the number the pointer has just passed or the 0 The next two dials are read the same way

The correct reading is 9 045 for the four-dial meter and 97 616 for the five-dial meter

ENVIRONMENTAL ISSUES

In the late 1960s increasing concern about environmental issues at the national level resulted in the creation of the Environmental Protection Agency (EPA) and promulgation of major Federal environmental laws such as the Clean Air Act, the Clean Water Act and the National Environmental Policy Act

During that time HL&P created an Environmental Department, and charged that department with ensuring that HL&P's operations complied with all applicable environmental laws and regulations However as the scope, content, and volume of environmental regulations mushroomed, and as public awareness of environmental issues and impacts increased, HL&P realized that environmental compliance was only a part of a responsible corporate environmental program Today, HL&P proactively seeks opportunities to enhance the environment and to promote responsible environmental management

Currently, HL&P's Environmental Department is composed of more than forty professional, technical, and administrative men and women with a variety of educational and work experience backgrounds The department is organized into three divisions Water and Ecological Resources Environmental Assessment and Waste Management, and Air Resources

One primary area of responsibility for this department is wildlife management and monitoring Typical activities include ensuring that normal Company operations do not unnecessarily impact wildlife populations, animal relocation, nuisance control and emergency situation response The department has also

actively participated in Texas Parks and Wildlife Department programs designed to define redfish migration patterns More than 6,000 redfish were tagged and released These fish were later caught by commercial and sport fishermen not only throughout the Galveston/ Trinity Bay systems but as far east as the Mississippi River

HL&P has been involved in waste recycling in a big way for many years The Company is actively involved in programs to recycle oil, batteries, antifreeze, paper, scrap metal and other materials The vast majority of the wastes generated by HL&P are ashes and sludge produced by coal and lignite combustion These materials have beneficial uses as feedstocks for other processes, such as a substitute for cement in the production of concrete or cinder blocks and as road base material By recycling these by-products, the need to acquire equivalent amounts of natural materials such as sand, gravel, shell, and limestone is avoided as are environmental impacts associated with mining and processing these materials The need to use landfill space for disposal of the combustion by-products is also avoided

In addition coal combustion by-products have been demonstrated to be useful as artificial reef substrate Availability of natural reef substrate in Texas bays has been impacted by a variety of activities To date, several reefs have been developed offshore in cooperation and consultation with various state and federal regulatory agencies Long-term monitoring is currently under way at several sites around Galveston Bay HL&P expects that this material will prove to be an excellent substitute for natural reef materials in both shallow and deep water environments

In an effort to promote the wise use of energy HL&P has established several energy efficiency and conservation programs These programs include

- Commercial and residential energy audits
- A "Good Cents" home and apartment program
- A commercial energy efficiency program
- A residential heat pump and high efficiency air conditioner replacement program
- A residential weatherization program for disadvantaged or low-income home owners

HL&P recognizes the critical need to conduct meaningful research into areas which can significantly reduce the environmental impacts of electrical generation and HL&P is a member of the Electric Power Research Institute (EPRI), one of the nation s largest private research organizations By participating in EPRI HL&P's research funds and other utilities' research funds can be pooled to maximize the benefit of research into these important environmental issues EPRI employs over 350 scientists and engineers to manage ongoing projects throughout the world Some examples

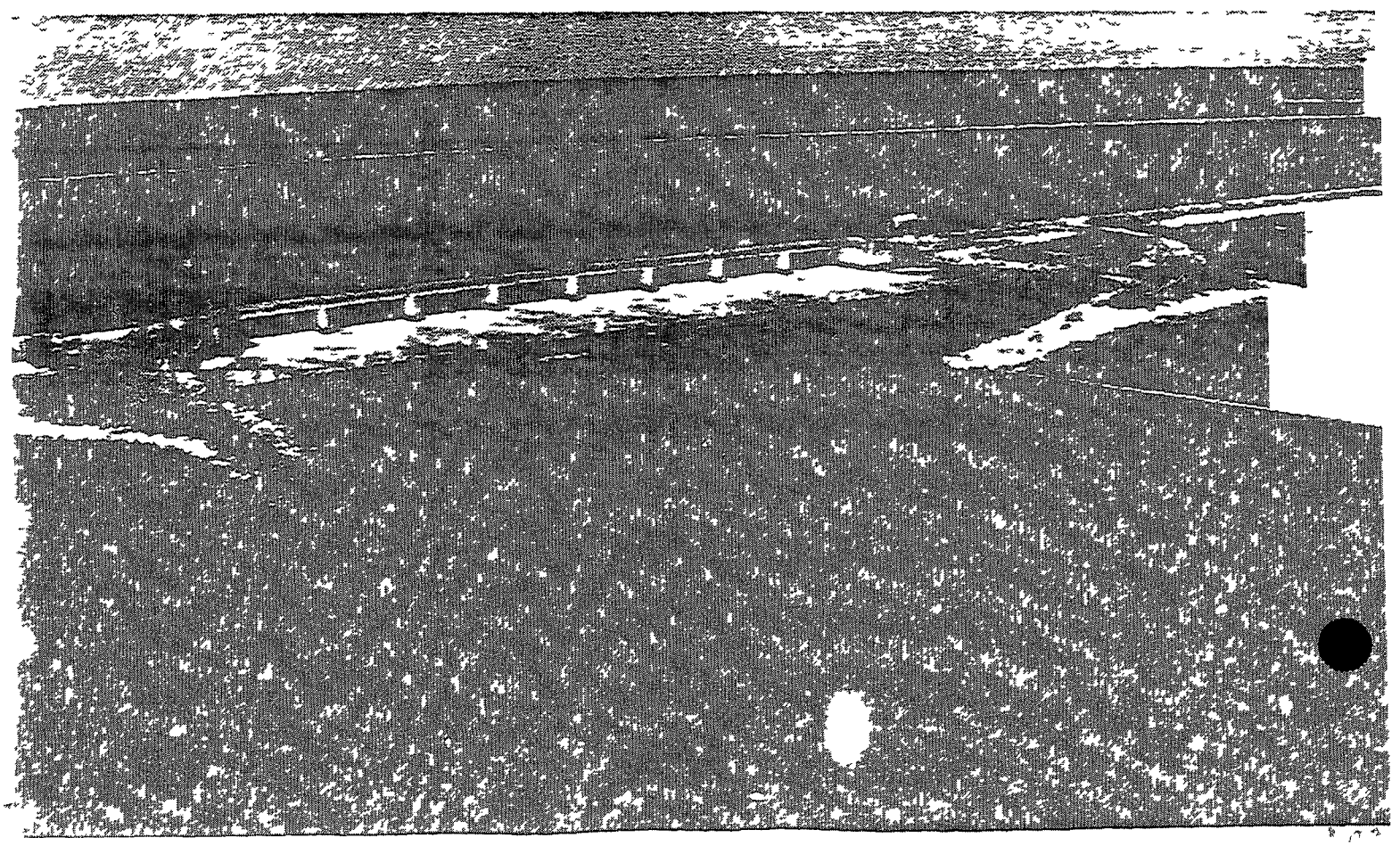
of the type of projects EPRI is involved in include (1) researching air quality, land and water quality, and electric and magnetic field issues, and (2) researching renewable resource options such as hydroelectric photovoltaics, waste to energy, biomass and geothermal energy sources

HL&P also funds several in-house research programs of particular interest These include Houston area ozone control strategies, electric car development, greenhouse gas emissions and solar power panels and streetlights

To maintain the level of compliance, HL&P uses an Environmental Performance Index which regularly evaluates each power plant's environmental compliance and gives the plant a score The scores are compared to annual targets which are linked to plant performance and individual compensation

The commitment to environmental protection at HL&P is also evidenced by the active roles assumed by HL&P employees in organizations such as the Galveston Bay National Estuary Program, and the Houston-Galveston Area Council Natural Resources Advisory Committee In addition, HL&P is actively involved in community environmental awareness and education activities including school classroom lectures and the corporate Speakers Bureau program

HL&P has a strong commitment to the environment and will continue to pursue opportunities to improve the environment that we all live and work in



POWER PURCHASES AND SALES

HL&P purchases power from Qualifying Facilities (QFs) and other ERCOT utilities The purchased power from the QFs can be firm capacity or non-firm capacity

Power sales and purchase transactions with other ERCOT utilities are of the following categories

- Brokerage
- Economy A
- Economy B
- Economy C
- Replacement
- Emergency

Economy A and Brokerage energy are interruptible on notification Transactions are decided on the preceding hour

Economy B and C are firm transactions Economy B transactions are committed 24 hours in advance Economy C transactions are committed 4 hours in advance Capacity replacement transactions are similar to Economy B, but could be for longer terms

Emergency power can be purchased or sold on a short notice in case of system emergencies

HL&P's Energy Management System (EMS) Long Term/Medium Term Resource Forecast (LTRF/MTRF) plans are used to develop power purchases and sales quotations The objective is to purchase power from other ERCOT companies when it is less expensive than internal generation production cost, and to sell power to other ERCOT utilities when HL&P can produce power at a lower cost The buying and selling of power in this manner is an economic benefit to HL&P customers

FUEL

Fuel Consumption

Natural Gas	217,998,733	Mcf[1]
Coal	10,433,212	Tons
Lignite	8,960,362	Tons
Nuclear	45,519,126	MMBtu[2]
Fuel Expense	$ 860,936,000	

Average cost of ..el (per million Btu) $ 1.54

Average Cost of Gas	$ 1 90
Average Cost of Coal	$ 1 59
Average Cost of Lignite	$ 1 11
Average Cost of Nuclear	$ 0 57

Electric Generation Energy Sources

	1994	Projected 2000
Natural Gas	34%	40%
Coal and Lignite	43%	41%
Cogeneration	16%	11%
Nuclear	7%	8%

Note There is no assurance that the various assumptions upon which the projections for the year 2000 as set forth in the table above will prove to be correct HL&P's actual energy mix in future years may vary from the percentages shown in the table

[1] Thousand cubic feet
[2] Million British thermal unit

Data as of December 11, 1994

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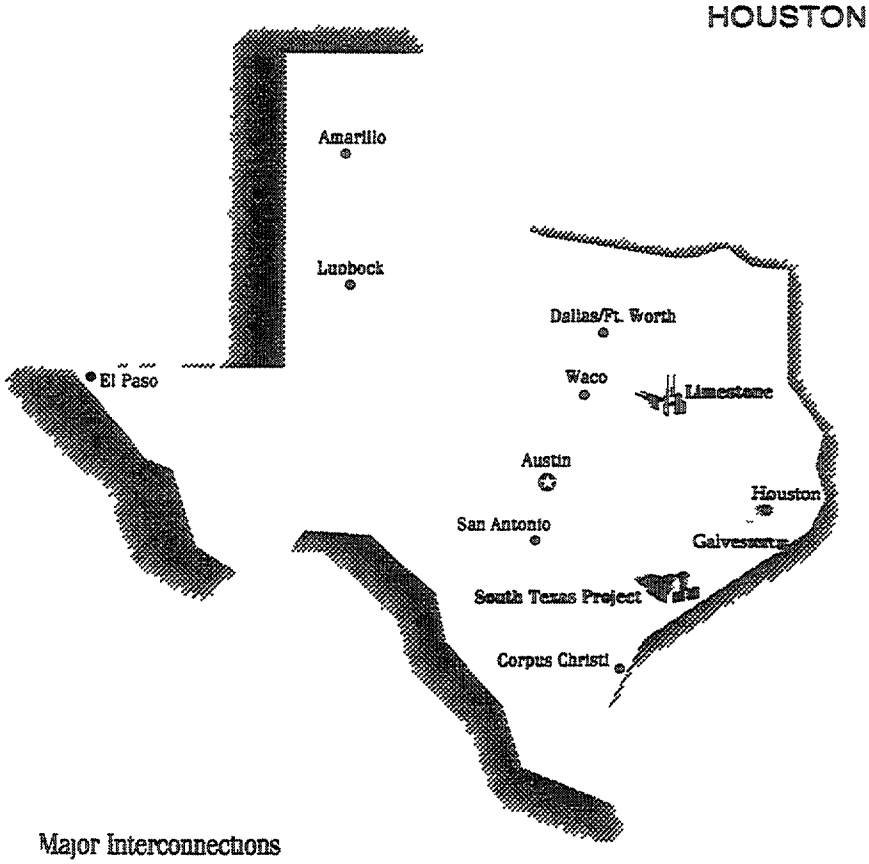
HOUSTON LIGHTING & POWER COMPANY

SERVICE AREA



Houston Lighting & Power serves a 5 000 square-mile area in the Gulf Coast region of Texas At the end of 1994 HL&P served approximately 1 4 million customers

Major Interconnections

Texas Utilities Electric Company

Central Power & Light Company

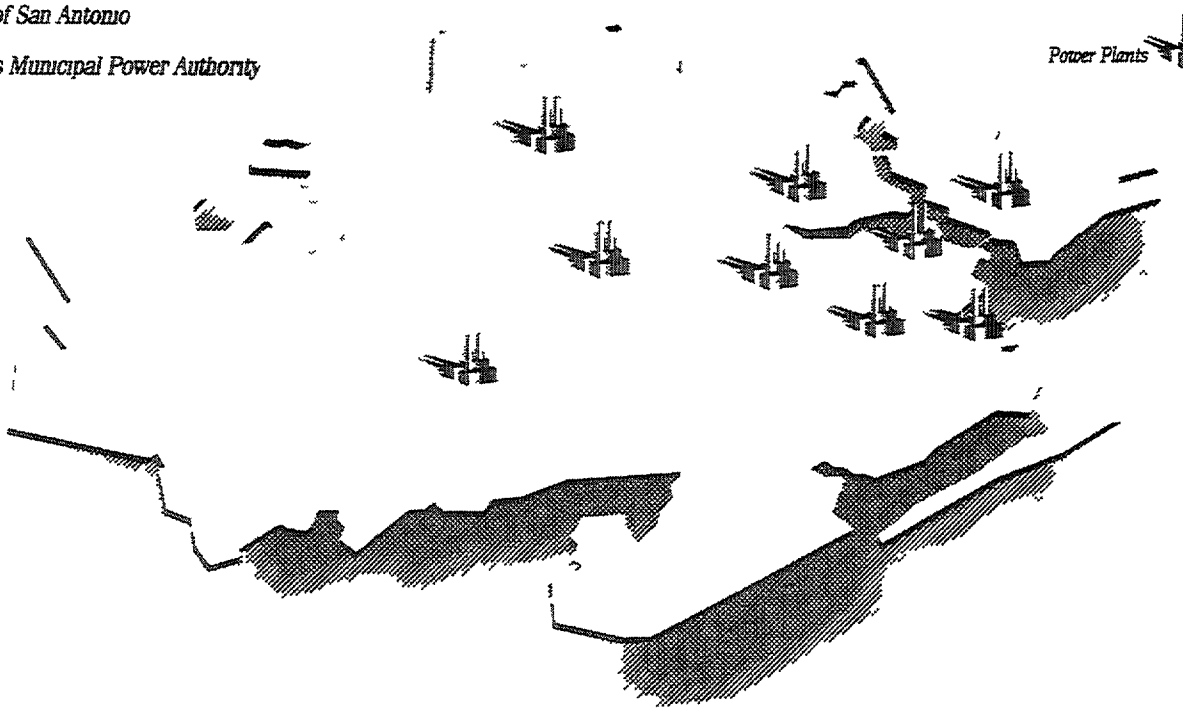
City of Austin

City of San Antonio

Texas Municipal Power Authority

345 KV Transmission Lines

Power Plants



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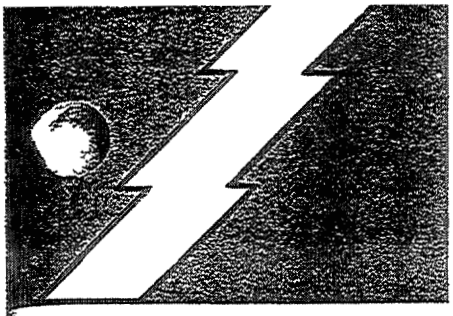
REA BULLETIN 161-1
MARCH 1972



INTERRUPTION REPORTING and SERVICE CONTINUITY STANDARDS for ELECTRIC DISTRIBUTION SYSTEMS

U S DEPARTMENT OF AGRICULTURE • RURAL ELECTRIFICATION ADMINISTRATION

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FOREWORD

This revised bulletin contains a suggested form for reporting service interruptions, standard names and codes for the causes of interruptions, and standard formats for summarizing experience. These standards were developed from the experience of managers, engineers and operating people on rural electric systems. We urge you to take full advantage of this experience of others in the electric utility industry. Wherever data are collected, results are better and costs are less if people are willing to plan carefully and agree on the kind of information needed and the ways it will be used.

Your attention is invited particularly to the ways of using summaries and reports discussed in this bulletin, including monthly reports to your power supplier about supplier-caused interruptions to service.

We thank those who provided the ideas and comments that are included and hope this information will be helpful to others.

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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

March 31, 1972
Supersedes 2/1/56

REA BULLETIN 161-1

SUBJECT: Interruption Reporting and Service Continuity Standards for Electric Distribution Systems

I. Purpose and Scope:

This bulletin provides suggestions on recording and reporting service interruptions (outages) and on the use of interruption records in the operation and maintenance of electric distribution systems. The bulletin does not include discussion of system engineering and design as related to service reliability. The influences of electric system planning, design and sectionalizing are discussed in REA Bulletin 60-7, Service Reliability.

II. General:

A. Purposes of Interruption (Outage) Records. The quality of electric service depends greatly on freedom from significant service interruptions; therefore, knowledge is required about the number and extent of interruptions, their causes, and the steps being taken to improve the continuity of service.

Well-planned procedures for interruption reporting and analysis will improve efficiency in handling trouble calls and responding to them so that the work can be done promptly and with a minimum of wasted motion.

The main purposes of interruption reporting and followup are:

1. To help make certain when a trouble call is received, that all of the information needed for responding to the trouble call will be available.

2. To identify multiple reports from the same line outage in order to expedite work and minimize confusion in storm and disaster situations.

3. To provide a record of causes and extent of interruptions, for determining adequacy of maintenance and for planning system improvements to increase service reliability.

4. To aid in informing consumers and in responding to consumer complaints.

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5. To provide information required by power suppliers, public service commissions and REA.

B. Descriptions of Units and Terms

1. The terms interruption and outage are interchangeable for much of this discussion. Present usage favors interruption when referring to loss of service to consumers, and outage when referring to components of a system. The following definitions are proposed by the IEEE Power System Engineering Committee.

> "Interruption. An interruption is a loss of service to one or more consumers or other facilities and is the result of one or more component outages."

> "Outage. An outage describes the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of service to consumers depending on system configuration."[1]

2. For discussing the quality of service, or service reliability, other terms are needed to define the extent of interruptions:

   a. Annual service interruption hours per consumer is the interruption index specified by REA to indicate the average length of time each year that a consumer on the system is without service. The unit for measuring this interruption is the consumer-hour, i.e., the product of the number of affected consumers multiplied by duration of the interruption in hours. The annual service interruption hours per consumer is calculated by adding consumer-hours for all interruptions during the year and dividing the sum by the average number of consumers receiving service during that period. The index may be maintained separately for parts of the system such as substations or service districts, or by causes, but the index for the entire system should always be calculated.

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1. References are listed at the end of the bulletin.

b. Service interruption hours per consumer, "year-to-date" has been found to be helpful in compiling a monthly or quarterly report for comparing with like months of previous years.

c. The number of interruptions experienced during a month, quarter, or year helps to indicate the amount of crew time required for service or maintenance because of outages from particular causes. Some systems maintain records for the cost of restoring service.

III. Interruption Reporting:

A. Reporting Forms. A suggested interruption reporting form is provided in Figure 1. This form may be used as shown, printed on both sides of a card if desired, or adapted as necessary to fit local conditions or individual reporting procedures. The front side of the form may be printed on both sides of a narrow card rather than on the 5-inch by 8-inch card, if desired. The form is designed for entering information in a logical sequence as follows:

1. For the person receiving the call.

2. For the dispatcher or superintendent.

3. For completion, followup, evaluation and review.

Looking at the front of the suggested form, the person receiving the trouble call fills in the top portion but omits the report number. The information in and to the right of the box, through "Location of Cause, if Known," helps in making certain that all of the needed information is obtained at the time of the call. The time of the call is entered following the date, and the "Time Power Went Off," is also taken for use later in calculating duration of the interruption.

The superintendent, operations manager, or dispatcher may enter "Recloser or Tap Location" in the event of a feeder outage. This information will assist in determining number of consumers out of service. At the same time, if more reports are coming in, he can decide which of them are due to the same line outage. This is particularly important during storms when many reports are being received.

The action taken, the time (or times) of restoring service and the material or equipment responsible for the interruption are usually taken from work reports and/or voice reports to the dispatcher.

Figure 1. Interruption Report. This design is for a 5-inch by 8-inch card. It may be divided horizontally for printing on both sides of a narrower card if desired.

INTERRUPTION REPORT

REPORT NO

DATE | TIME | RECEIVED BY

ACCOUNT NO | REPORTED BY | PHONE NO | TIME POWER WENT OFF

ADDRESS

- ☐ SERVICE OFF ENTIRELY
- ☐ NEIGHBORS ALSO OFF
- ☐ SERVICE DROP DOWN
- ☐ LIGHTS DIM
- ☐ CHECKED FUSES

CAUSE IF KNOWN

LOCATION OF CAUSE IF KNOWN

RECLOSER OR TAP LOCATION | ASSIGNED TO | TIME | TRUCK NO

ACTION TAKEN

RESTORED SERVICE TO | TIME | REMARKS

RESTORED SERVICE TO | TIME

RESTORED SERVICE TO | TIME

MATERIAL OR EQUIPMENT CAUSE OF INTERRUPTION | CODES

REVIEWED BY

Dispatcher | Superintendent | Engineer

Figure 1. (Continued) These checklists are for printing on back of 5-inch by 8-inch card if desired.

Plant Codes *(Material or Equipment) (Check One)*

☐ 00 Power Supplier

Substation *(owned)*

- ☐ 10 Transformer
- ☐ 11 Regulatr or brkr
- ☐ 12 Sw or lgtn arr
- ☐ 13 Source fuse
- ☐ 19 Other

Distribution

- ☐ 20 Pole
- ☐ 21 Crossarm or brace
- ☐ 22 Anchor or guy
- ☐ 29 Other fixture

Overhead Line *(Distn)*

- ☐ 30 Conductor
- ☐ 31 Connector clamp
- ☐ 32 Splice deadend
- ☐ 33 Jumper
- ☐ 34 Insulator
- ☐ 35 Ligtng arrestr
- ☐ 36 Fuse or cutout
- ☐ 37 OCR or sectzr
- ☐ 39 Other device

Underground

- ☐ 40 Primary cable
- ☐ 41 Splice fitting
- ☐ 42 Switch
- ☐ 43 Lgt arr for URD
- ☐ 44 Sec cable or fittings
- ☐ 49 Other

Line Transformer

- ☐ 50 Bad replaced
- ☐ 51 Fuse or breaker
- ☐ 52 Lighting arrester

Secondary, Service

- ☐ 60 Wire
- ☐ 61 Meter or loop
- ☐ 62 Security or street light
- ☐ 69 Other

☐ 99 Unknown

Generation or Transmission, If owned

- ☐ 01 Generation
- ☐ 02 Towers, poles fixtures
- ☐ 03 Conductors and devices
- ☐ 04 Transmission substation
- ☐ 09 Other

Cause *(Check One)*

☐ 00 Power Supplier

Scheduled

- ☐ 10 Construction
- ☐ 11 Maintenance
- ☐ 19 Other

☐ 20 Major Storm

Equipmt or Inst

- ☐ 30 Matl or equip fault
- ☐ 31 Install fault
- ☐ 32 Sag clearance
- ☐ 39 Other

Age or deterioration

- ☐ 40 Decay
- ☐ 41 Woodpeckers
- ☐ 42 Corrosion
- ☐ 43 Contamination *(leakage)*
- ☐ 44 Moisture
- ☐ 45 Elec overload
- ☐ 49 Other

Weather

- ☐ 50 Lightning
- ☐ 51 Wind not trees
- ☐ 52 Ice not trees
- ☐ 53 Trees and ice
- ☐ 54 Trees other
- ☐ 59 Other

Birds Animals

- ☐ 60 Small cause short circuit
- ☐ 61 Large forced pole or anchor
- ☐ 69 Other not woodpeckers

Public

- ☐ 70 Vehicles
- ☐ 71 Aircraft
- ☐ 72 Accidents other
- ☐ 73 Vandalism
- ☐ 74 Fire
- ☐ 79 Other

☐ 99 Unknown

To calculate the interruption time in consumer-hours, the elapsed time in hours between "Time Power Went Off" and "Service Restored" is multiplied by the number of consumers affected. If service was restored in several steps, the calculations should be made separately and then added together. For example, if a recloser is tripped due to a broken (by gunfire) bushing on a distribution transformer (internally fused), we might have:

Restored service to main line at 3:42 P.M.

Restored service to Joe Black at 6:20 P.M.

If the "Time Power Went Off" was 3:00 P.M., and the line serves 31 consumers including Joe Black, the consumer-hour calculation is:

$$30 \text{ consumers} \times \frac{42}{60} \text{ hour} = 21.00 \text{ consumer-hours}$$

$$1 \text{ consumer} \times 3 \text{ hrs. } 20 \text{ min.} = 3.33 \text{ consumer-hours}$$

$$\text{Total for interruption} = 24.33 \text{ consumer-hours}$$

Codes shown may be printed on the reverse side of the form if desired. The report number is usually assigned after duplicate reports have been eliminated; it is used for locating, where the reports are filed chronologically, and for chronological listings of interruptions if desired.

Whenever an outage occurs on a feeder, it will be necessary to enter the number of affected consumers on the report form. This will require a record of the number of consumers beyond each sectionalizing point. Provision must be made to keep this information up to date.

B. Filing for Future Reference. The completed reports may be filed in simple chronological order, if the number is small. However, a file according to substation, feeder and sectionalizing point should be considered for systems of average or larger size. It may also be desirable to file individual consumer interruptions by account number, separately from line outages.

The filing arrangement should be carefully selected in light of detailed uses that may be made of the interruption information. Even though the number of reports per year or quarter may be large, many kinds of special evaluations can be made very effectively from the original reports. The burden of detail in summaries and in the data routinely processed may thus be reduced.

C. Interruption Log. A log such as shown in Figure 2 provides an orderly method of entering interruption information as calls are received, if a log is desired. However, some electric superintendents and managers have said they do not use an interruption (or outage) log because the reporting form is all that is needed. Others have radio logs which are adequate for this purpose.

Two cautions against use of the interruption log are:

1. It may represent unnecessary duplication of details that should be on the interruption report instead.

2. It may be taking the place of an interruption or outage summary, yet be poorly designed for that purpose, so that the interruption information is not being used to best advantage.

IV. Causes of the Interruptions: Categories and Codes -

A. Reports to REA. Borrowers are asked to report on REA Forms 7a[2] and 300[3] the average annual interruption hours per consumer due to causes in each of four major categories:

Power supplier

Major storm

Scheduled

All other

"Scheduled," for this purpose, refers to interruptions resulting when a distribution transformer, line or owned substation is deliberately taken out of service at a selected time for maintenance or other reasons. The interruptions resulting from either scheduled or unscheduled outages on lines or substations owned by the power supplier are charged to "power supplier."

"Major storm" represents service interruptions from conditions which cause many concurrent outages because of snow, ice or wind loads that exceed design assumptions for the lines.

Most service interruptions are for reasons in the category, "All other." These are the ones resulting from emergency conditions due to equipment breakdown, malfunction, or human error.

Figure 2. Interruption Log

Month _____ Year _____

Report No.	Date	Time	Received By	Reported		Truck No.	Cause	Location Of Cause
				By	Phone No.			

B. Standard Codes for Interruption Analysis. The detailed categories for service interruptions, Tables 1 and 2 of this bulletin, have been carefully selected so that the important ones may be clear r seen when the interruption data are summarized. Numer al codes are assigned. These are recommended for use as andard codes for data processing.

To avoid excessive detail, the number of individual reasons (codes) has been kept to a minimum. In addition, they are arranged in groups -- nine for "Equipment or Material Responsible for Interruption" and nine for "Cause of In+ ıption." The two codes for equipment or material ar ıse are designed so that together they will provide t: eded information about reasons for the interruption.

Th mportance of keeping detail to a minimum can hardly be overemphasized. When comparisons are to be made, such as between substation areas or feeders, sometimes on a quarterly or month-by-month basis, how much detail do you really want? When additional detail is needed for a special study, it is generally best to go back to the original reports for more information.

Additional detail codes or even group codes may be assigned to allow for circumstances that are particularly important a geographic area or in a particular electric system. rs are urged to keep such codes to the absolute minimum.

C ecial Studies. Interruption reports may be a valuable urce of information about performance of transformers or other equipment, or about soil or terrain conditions that have impo a t effects on maintenance costs or quality of service. details may be summarized from the original reports d. However, it is generally a mistake to design a al plan of interruption analysis to encompass suc l. The resulting procedures and reports become me and costly and too often fail to accomplish the ary purposes of interruption analysis.

V. Interrupti n Experience: Summaries and Reports

A. For Oper n and Maintenance. Tables 3, 4 and 5 show suggeste vs to summarize interruption experience for purposes electric system operation and maintenance.

1. Table , shows comparisons of experience ir individual substation areas, in terms of the number c nterruptions (service calls) and summations of cc mer-hc rs (the er of consumers multiplied by ho repre- sent ne time that consumers were withc electric

Table 1. Equipment or Material Responsible for Interruption

Code	Description	Items in Acct. No
00	Power Supplier	
	Generation or Transmission (If Owned)	
01	Generation	
02	Towers, poles and fixtures	354, 355
03	Conductors and devices	356-358
04	Transmission substations	353
09	Generation or transmission, other	
	Distribution Substation (Owned)	362
10	Transformer	
11	Voltage regulator or breaker	
12	Lightning arrester or switch	
13	Source side fuse	
19	Other	
	Poles and Fixtures, Distribution	364
20	Pole	
21	Crossarm or crossarm brace	
22	Anchor or guy	
29	Other	
	Overhead Line Conductors and Devices, Distribution	365
30	Line conductor	
31	Connector or clamp	
32	Splice or deadend	
33	Jumper	
34	Insulator	
35	Lightning arrester, line	
36	Fuse cutout (damaged, malfunction or maintenance)	
37	OCR or sectionalizer (damage malfunction or maintenance)	
39	Overhead distribution line, other	
	Underground Conductor or Devices, Distribution	366, 367
40	Primary cable	
41	Splice or fitting	
42	Switch	
43	Lightning arrester for URD	
44	Secondary cable or fittings	
49	Underground, other	
	Line Transformer	368
50	Transformer bad, replaced	
51	Transformer fuse or breaker, refused or reset	
52	Transformer lightning arrester	
	Secondaries and Services	369, 370
60	Secondary or service conductor	
61	Meter or meter loop	
62	Security light or street light	
69	Other	
	Unknown	
99	Open OCR, sectionalizer or fuse, source of difficulty not known	

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Table 2. Cause of Interruption

Code	Description
00	Power Supplier
	Scheduled
10	Construction
11	Maintenance
19	Other
20	Major Storm Disaster
	Equipment or Installation
30	Material or equipment fault
31	Installation fault
32	Conductor sag or clearance not adequate
39	Faulty material or installation, other
	Age or Deterioration
40	Decay
41	Woodpeckers
42	Corrosion or abrasion
43	Contamination (leakage)
44	Moisture
45	Electrical overload
49	Age or deterioration, other
	Weather
50	Lightning
51	Wind, not trees
52	Ice, sleet, frost, not trees
53	Trees and ice
54	Trees, other
59	Weather, other
	Birds or Animals
60	Small animal or birds (short circuit)
61	Large animals (affecting pole or guy)
69	Birds or animals, other (not woodpeckers)
	Member (or Public)
70	Vehicles or machinery
71	Aircraft
72	Public accidents, other
73	Vandalism
74	Fire
79	Activities of the public, other
	Unknown
99	Cause of interruption not known

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Table 3. Interruptions Due to Each Cause -- November 1971

Substation and Cause	This Month Number	This Month Consumer-Hours	Year-to-Date Number	Year-to-Date Consumer-Hours
North Fork				
Power supplier	0	0	6	670.5
Scheduled	3	1.8	6	6.9
Major storm	0	0	35	1803.6
Unscheduled, other:				
Equipment or installation	0	0	15	63.1
Age	3	15.2	18	71.4
Weather	2	10.8	9	34.7
Birds or animals	1	6.2	6	62.1
Public	3	4.8	3	6.9
Unknown	3	3.5	33	22.8
Subtotal (Unscheduled)	12	40.5	84	261.0
Substation Total	15	42.3	131	2742.0
Wideawake				
Power supplier	1	556.2	4	1710.7
Scheduled	3	7.5	8	27.6
Major storm	1	401.8	2	842.3
Unscheduled, other·				
Equipment or installation	3	29.2	4	11.5
Age	0	0	12	142.6
Weather	0	0	15	73.2
Birds or animals	1	5.2	4	21.6
Public	2	20.4	2	8.1
Unknown	3	3.6	32	43.6
Subtotal (Unscheduled)	9	58.4	69	300.6
Substation Total	14	1023.9	83	2881.2
(Other substations follow)				
Total, entire system	104	1342.6	749	19681.2

Consumers served: 5,256 (average, 11 mo.)

Average hours interrupted: 3.74 (year-to-date)

service. This information is given separately for each major cause as shown in Table 2, for each substation service area. The example shows a monthly summary form. For small electric systems with relatively few interruptions, a quarterly summary may be preferable.

2. Table 4 gives details about the material or equipment items that were responsible for interruptions, using the same items that are shown on the code list, Table 1. For each item, the consumer-hour figures may be shown separately for each major cause of interruption as shown in columns across the page. For small systems, a quarterly summary may be preferable to the monthly one shown. Other variations of this summary may be desirable, depending on circumstances:

   a. A separate summary for a month or quarter, excluding previous experience in the same year, may be preferred.

   b. The number of interruptions (as well as consumer-hours) as shown in Table 3 may be desirable, in the first column (All Causes) or in all columns.

3. Table 5 gives additional details about causes of interruptions, using the same causes as are listed in the code list of Table 2. The information is further broken down according to major equipment or material items responsible, in a format like that of Table 4.

4. While not recommended for general use, other types of reports have been used to advantage and may be desirable in some situations:

   a. A report of the largest total hours on interruption for an individual consumer or line section. This might be a tabulation with one line per line section, distributed according to cause (group codes, only), including line sections with more than 10 hours (or some other specified number) of total interruption time during the year.

   b. A report of the elapsed time between the time of interruption and the time of the trouble report. This might be tabulated, one line per "Cause" category on nine lines distributed according to equipment or material category (nine columns).

Table 4. Interruptions Due to Material Items -- Year through December 1971

	Equipment or Material	All	Power Supplier 00	Scheduled 10-19	Major Storm 20	Equipment or Installation 30-39	Age 40-49	Weather 50-59	Birds & Animals 60-69	Member or Public 70-79	Unknown 99
		Cause of Interruption (Consumer Hours)									
00	Power Supplier	1580 0	1580 0								
	Generation & Transmission (Owned)										
01	Generation										
02	Tower or pole	780 9		66 1	294.3	92 4	58 0	108 6		133 7	27 8
03	Conductor	797 3		93 6	262.6	68 2	8 5	163.7	56 8	115 4	28 5
04	Substation	744 4		28 2	257.0	69.0	76.5	194.2	38.4	56 1	25 0
09	Other	479 0		8 4	280 1	51 5	16 3	78.3	3 4	23 9	17 1
	Subtotal	2801 6		196.3	1094 0	281.1	159 3	544.8	98.6	329.1	98 4
	Distribution Substation (Owned)										
10	Transformer	1147 1		328 0	184 2	181 6		163 5		171 3	118 5
11	Regulator or Breaker	503 9		211 8		58.4	18.9	91.1	48 9	22 6	52 2
12	Switch or Arrester	82 9		19.2	9.4	8.0	21.4	7 2		9.1	8 6
13	Source Fuse	132 7		67 6		37 1				14.2	13 8
19	Other	275 9		147 9		27 2	28 1			44 2	28 5
	Subtotal	2142 5		774 5	193.6	312 3	68.4	261 8	48 9	261.4	221 6
	Poles & Fixtures (Distribution)										
20	Pole	2969 8		374 2	1232 6	309 4	191.0	518 7	77.9	93.0	173 0
21	Crossarm or Brace	1086 7		196 8	513 3	77 9	63 3	172 1			63 3
22	Anchor or Guy	1016 9		109 4	222 5	189 0	56.1	228 2	77 5	75.0	59 2
29	Other	344 4		67 9	94 5	42 1	13 3	29 6	26 7	50 5	19 8
	Subtotal	5417 8		748 3	2062.9	618 4	323 7	948 6	182.1	218 5	315 3
	Overhead Conductor & Devices (Distribution)										
30	Line Conductor	2459 4		305 1	1048 7	122 2	13 8	421 3		437.6	110 7
31	Clamp, Conductor	455 4		124 0	173 6	28 7		97 5	11.0		20 6
32	Splice, Deadend	469 1		62 8	217 8	47 8	7 2	88.6		23 8	21.1
33	Jumper	290 7		54 7	83.5	22 5		63 3	16 2	37 4	13 1
34	Insulator	981 9		216 5	236 7	83 7	13.6	85.4	23 7	278.0	44 3
35	Lightning Arrester	633 8		68.9	257 1	42 1		102 6	27 2	107 4	28 5
36	Fuse Cutout	943 1		127 7	415 9	126 8		157 8	33 5	38.9	42.5
37	OCR, Sectionalizer	481 0		68 3				113 7	74 6	202 8	21.6
39	Other	726 9		67 6	229 1	10 0	16 9	59 8	3 5	307 7	32 3
	Subtotal	7441 3		1095 6	2662 4	483 8	51 5	1190.0	189 7	1433 6	334 7
	Underground, Conductor or Devices										
40	Primary Cable	402 8		39 7		72 8		38 1	26 6	116.8	108.8
41	Splice or Fitting	99 8		7 1		13 4		23 3			56 0
42	Switch	53 1		11 4		9 6					32 1
43	Lightning Arrester	175 9		13 2		20.8		80 5	9 3	32 3	19 8
44	Secondary Cable or Fittings	188 5		9 7		53 6		55 0	13 3	30 6	26 3
49	Other	129 7		7 1		21 4		14 4			86 8
	Subtotal	1049 8		88.2		191 6		211 3	49 2	179 7	329 8
	Line Transformer										
50	Transformer Bad	1169 4		73 8	15 9	136 2	210 6	139 8	133 3	84 5	375 3
51	Transformer Fuse or Breaker	251 6		12 9	23 8			116 5	28 2	9 3	60 9
52	Transformer Lightning Arrester	552 3		5 6	119 0	27 2	25 9	208 9	26 6	21 9	117 2
	Subtotal	1973 3		92 3	158 7	163.4	236 5	465 2	188 1	115 7	553 4
	Secondaries and Services										
60	Secondary or Service Conductor	806 9		41 9	109 8	53.2	34.4	206 1	19 8	77 2	264 5
61	Meter or Meter Loop	403 5		37 8	14 5	26 4	23 5	79 7	37 6	37 8	146 2
62	Security or Street Light	338 9		19 9	17 7	45 7	42 6	72 9	41 5	58 3	40 3
69	Other	154 3			19 2	13 4	11 8	41 7		15 6	52 6
	Subtotal	1703 6		99 6	161 2	138 7	112 3	400 4	98 9	188 9	503 6
	Total	24109 9	1580 0	3094.8	6332 8	2189 3	951 7	4022 1	655 5	2726 9	2356 8

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Table 5. Interruptions Due to Each Detailed Cause -- Year through December 1971

	Cause	All	Power Supplier 00	Equipment or Material Responsible: Gen. and Transm. 01-09	Sub-station 10-19	Pole, Fixture 20-29	Overhead Line 30-39	Underground 40-49	Line Transformer 50-52	Secondary, Service 60-69
		(Consumer Hours)								
00	Power Supplier	1580.0	1580.0							
	Scheduled									
10	Construction	1455.7		37.2	324.1	326 7	643.8	49 2	41.6	33.1
11	Maintenance	1258.6		98.4	394.0	298.4	341.5	32.3	35.6	58.4
19	Other	380 5		60.7	56.4	123.2	110.3	6.7	15.1	8.1
	Subtotal	3094.8		196.3	774.5	748.3	1095.6	88.2	92.3	99.6
20	Major Storm	6332.8		1094.0	193.6	2062.9	2662.4		158.7	161.2
	Equipment or Installation									
30	Material or Equipment Fault	956.9		86.7	165.7	328 0	166.1	96 4	57.2	56.8
31	Installation Fault	769 1		72.8	96 6	235.3	142.2	83 3	86 2	52.7
32	Conductor Sag or Clearance	214.2		42.1	21.9		113 9		11.4	24.9
39	Other	238 0		78.4	28.1	55.1	51.6	11 9	8.6	4.3
	Subtotal	2189.3		281.1	312.3	618 4	483.8	191.6	163.4	138.7
	Age or Deterioration									
40	Decay	138.9		40.4		98.5				
41	Woodpeckers	156.5		30.3		90.6			35.6	
42	Corrosion or Abrasion	167.0		20 7	12.3	35.6	20.1		41.6	36.7
43	Contamination	75 3		11.5	11.6		14.4		37.8	
44	Moisture	211 0		31.9	15.7	76.4	7.2		47.3	32.5
45	Electrical Overload	126.3		19.1	22.6		4.1		56.7	23.8
49	Other	76 7		5.4	6 2	22 6	5 7		17 5	19 3
	Subtotal	951 7		159.3	68.4	323.7	51 5		236 5	112 3
	Weather									
50	Lightning	1213.8		59 8	188 0	170.6	369.1	188 4	153.8	84.1
51	Wind, Not Trees	479 9		54 5	39 2	151.6	130 0		60 6	44 0
52	Ice, Sleet, Frost	1117 0		316.2	34 6	303.7	286.1		65.2	111.2
53	Trees and Ice	534.7		38.4		113.8	202.2		88.5	91 8
54	Trees, Other	424.2		43.5		116.7	129.7		74.4	59 9
59	Other	252.5		32 4		92 2	72 9	22.9	22 7	9.4
	Subtotal	4022.1		544.8	261.8	948.6	1190 0	211.3	465.2	400.4
	Birds or Animals									
60	Small Animals or Birds	497.0		46 5	43 3	52.7	96.8	38.6	143.7	75.4
61	Large Animals	173 9		20.6		90.8	62.5			
69	Other	184 6		31 5	5 6	38.6	30.4	10.6	44.4	23 5
	Subtotal	855 5		98 6	48.9	182.1	189.7	49.2	188.1	98.9
	Member (or Public)									
70	Vehicles or Machinery	612.9		82.1	86 3	61.3	272.6	81.7	17.4	11 5
71	Aircraft	237 4		59.2			178.2			
72	Public Accidents, Other	540.3		76.4	20.9	116.0	284 2		22.0	20.8
73	Vandalism	690.7		46.0	125.4	24.1	331.4	98.0	3.5	62.3
74	Fire	449.1		29.2	28.8	10.9	215.3		70.6	94.3
79	Other	196 5		36.2		6 2	151.9		2.2	
	Subtotal	2726.9		329.1	261.4	218.5	1433.6	179.7	115.7	188.9
99	Unknown	2356.8		98.4	221.6	315.3	334.7	329.8	553.4	503.6
	Total	24109 9	1580.0	2801.6	2142.5	5417.8	7441 3	1049.8	1973.3	1703.6

Table 6. Interruption Summary

For Month of _____
Year _____

	Power Supplier	Major Storm	Sched-uled	All Other	Total
Number of Interruptions:					
This month					
This month last year					
This year to date					
Last year to this date					
Consumer-hours Interruption:					
This month					
This month last year					
This year to date					
Last year to this date					
Average Hours per Consumer:					
This month					
This month last year					
This year to date					
Last year to this date					

Data for Computing Average Hours per Consumer:

Number of Consumers Served this Month: _____

Average Number of Consumers This Year to Date: _____

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c. A report of the longest individual interruptions during the year. This could be a listing, one line per interruption distributed according to "Cause" category (nine columns), for interruptions of more than five hours or some other specified length of time.

B. For Directors and Members. Table 6, Interruption Summary, brings together the information most needed by the manager, the board of directors, and REA. This information can and should be prepared by hand from the other reports. This is easily done, and the use of data processing equipment for the report shown on Table 6 would be uneconomical. Newsletter reports to members also should not be forgotten. Emphasis might be upon interruptions influenced by activities of the public (see Table 2), on the results of delay in reporting that service is off, or on the progress being made in improving the quality of service. Newsletters or postcards may be used to notify consumers about scheduled interruptions.

C. For Power Suppliers and Regulatory Bodies. A report giving the data specified in Table 7 should be sent each month to each power supplier (and regulatory bodies as required), including all delivery points, along with indications of no interruption when applicable. If the power is delivered through the facilities of a party other than the power supplier, reports to both may be desirable. The information in Table 7 is required by REA power-type borrowers for a monthly report (Form 12g4) to REA. For other power suppliers, the information outlined in Table 7 will serve as a regular reminder of the reliability of service being provided and the need for improvement when experience so indicates.

Table 7. Interruption Report to Power Supplier

For Month of _____
Year _____

Delivery Point	Interruption Time		Date	Time	
	Hours	No. of Consumers Affected		Off	Restored

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VI. Service Continuity Objectives:

Every electric system should be providing the best service available. To do this, standards or goals are needed to establish the level of service reliability considered necessary to meet consumers' needs. This is true even though there may be wide variations in the levels that are feasible for particular systems.

Electric utilities in largely urban areas tend to aim at one hour or less service interruption per year for the average urban consumer and two hours or less for the average rural consumer. However, many rural electric systems would have difficulty meeting such goals because of longer lines, severe environmental conditions, and more frequent interruptions of power supply.

The present REA criteria for rural distribution systems are shown in Table 8.[3]

Systems that are well engineered and have experienced favorable weather during the year should expect considerably less than five consumer hours per consumer during the year. Conversely, in some situations it may not be possible to achieve the figure of five consumer hours per consumer per year.

Table 8. REA Service Reliability Criteria for Rural Electric Distribution Systems

Description	Average Service Interruption Consumer-Hours per Consumer per Year
Satisfactory	5 or less
Should be explained	More than 5

The significance of a high interruption hour figure will depend on circumstances. For example, long interruptions may result from severe ice or wind loads, or excessive interruptions may be due to trees, lightning or scheduled outages showing the need for corrective measures or different work procedures. When the satisfactory level is exceeded, management should examine the causes, consider the ways available to prevent the excessive interruptions and develop time, work, and cost schedules for future corrective action.

James A. Thyen
Assistant Administrator - Electric

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REFERENCES

. IEEE Power System Engineering Committee Report, "Definitions of Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service" May 1971

2 REA Bulletin 108-1, Electric Distribution Borrowers' Financial and Statistical Reports

3. REA Bulletin 161-5, System Operation and Maintenance Review and Evaluation

4 REA Bulletin 108-2 Operating Report -- Power Supply Borrowers and Distribution Borrowers with Generating Facilities

Index:
RECORDS:
Interruption Reporting
REPORTS.
Interruption
SYSTEM OPERATIONS AND MAINTENANCE.
Interruption Reporting and Service Continuity

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REA BULLETIN 45-2

June 1963

DEMAND TABLES

RURAL ELECTRIFICATION ADMINISTRATION • U.S. DEPARTMENT OF AGRICULTURE

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PREFACE

The tables in this bulletin have been prepared for determining demand data to be used in connection with engineering studies on rural distribution systems. They are based on 1954-1955 load data obtained from systems throughout the country. A check of current data has shown that the tables are still applicable. This has been confirmed by operating expe ce. A short discussion is included to acquaint those using the bulletin with the basic data and ods used in its preparation in order to provide a better understanding when app ying the in ion to specific problems. An attempt has been made to anticipate and answer questions whi be in the minds of those using the "Demand Tables."

Four methods are provided for the calculation of demand, all o which will give essentially the same results. They are:

1. The use of Consumer Factor "A" and KWH Factor "B" from the tables.

2. The use of nomograms which are based on Fact s "A" and "B".

3. The use of Factors "A" and "B" as obtained the equations

Factor "A" = C[1 - .4C + .4(C^2

Where C = number of consumers

Factor "B" = .005925(KWH/mo/consumer) .885

This is computers.

4. The use of the bles from which demand may be directly.

In the methods for determ demand data, which make use of mer Factor (F tor "A") and KWH Factor (Factor "B") Factor "A" reflects the improved dive y resulting from an increase in the number of consumers, and Factor "B" reflects the improvement in load factor with increased usage. "KW demand" equal to the product of Factor "A" and Factor "B". It will be noted that above 1400 con Factor "A" is, for all practical purposes, equal to the number of consumer Factor "B" ma otted as a straight line on log-log paper.

The demand obta d by any of the four methods is based on the ave e system, d some systems will deviate from the average because of a difference in load fact These methods may be adapted to a particula stem by selecting the appropriate table or calcu ting a multiplying factor as shown in Secti

KW demands this bulletin are those h may be expected for any particular monthly usage. Therefore, to in the maximum yearly de the maximum monthly usage, rather than the average usage, should be used.

KW = Factor × Factor

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DEMAND TABLES

I. BASIC INFORMATION

The information for this bulletin, except for the smaller numbers of consumers (less than 50), was taken from operating reports and power bills furnished by REA borrowers. A 25% sample was taken from each area, also representing so far as possible 25 percent of those in each state. One substation was selected from each system avoiding those with unusual loads, such as army installations, large industrial plants, and seasonal cottages. These were not used because the effect of such loads is included separately in engineering studies. In several cases it was necessary to discard a sample because of unusual conditions which were not representative of a rural system, resulting in a reduction of the sample to approximately 23 percent.

To avoid irregularities in meter reading times, the four-month peak demand period (four consecutive months) was selected for determining monthly usage and demand. The values used in preparing the tables were the average monthly usage and the average monthly demand over this four-month peak period of maximum demand. Therefore, the kw demand data in the bulletin are those which may be expected for any particular monthly usage. To obtain the maximum yearly demand, the maximum monthly usage, rather than the average usage, should be applied in reading the tables. The kwh values used are based on kwh sold at the consumer's meter, making it unnecessary to correct for losses.

Information available in REA for small numbers of consumers could not be used, since it was found that substations with only a few consumers were those with unusual loads and not representative of a typical rural area. The data in this range were obtained from a study made on 42 farms by the Agricultural Experiment Station, Iowa State College, and the Farm Electrification Section, Agricultural Research Service, U. S. Department of Agriculture. The information is contained in Iowa State College Research Bulletin 420, January 1955, "Load Characteristics of Southeastern Iowa Farms Using Electric Ranges."

II. METHOD OF PLOTTING DATA

The data were plotted as KWH/Mo/KW vs. Consumers, the ordinate being a measure of diversity. A notation was made by each point indicating the area from which it was taken. The peak month and density were also noted on a separate sheet. An examination of the points showed no noticeable difference because of area or density. However, a spot check indicated that about three-fourths of the summer peaking systems will have a lower demand than the average and one-fourth higher than average.

*This revision combines REA Bulletin 45-2, dated August 1956, and the supplement, dated June 1957, under one cover.

From past experience and by inspection it could be seen that the plot of KWH/Mo/KW vs. Consumers would be a family of curves, each curve representing a particular value of kwh/mo/consumer. Knowing this to be true, one curve would have been sufficient, but in order to prove the point three curves were plotted. Because of the lack of sufficient points to plot specific values of usage, curves were plotted for three ranges: 101-200, 201-400, and 401-600 kwh/mo/consumer.

Figure 1 shows the spread of points for 401-600 kwh/mo/consumer. A curve was drawn through these points by the method of moving averages. The original curve was carried to 10,000 consumers but as a matter of convenience Figure 1 has not been reproduced beyond 2,000 consumers since the curve continues in a straight line.

In Figure 2 this same curve has been reproduced with the other two curves mentioned above for comparative purposes. It will be noted that the three curves have the same shape and level off at approximately 1400 consumers. Any point on either curve may now be identified as a given percentage of the maximum kwh/mo/kw for that curve. For example, using a given number of consumers, a point which is 50 percent below the maximum on one curve will be 50 percent below the maximum for any curve in the family.

To find the maximum for any curve in the family, it was necessary to find some relationship between the maximum values for the three curves plotted. The three points appeared to form a straight line on log-log paper, but more points were needed to verify this assumption. This was accomplished by making a plot of all points above 1400 consumers (Fig. 3), since the effect of the third variable, consumers, is constant in that range as shown by the curves in Figure 2. A curve drawn through these points by the method of moving averages verified the previous assumption that the plot would form a straight line on log-log paper. This straight line curve was also in agreement with a straight line drawn through the three points of maximum value found in Figure 2.

III. CALCULATION OF KW DEMAND

The following equation was derived for calculating demand from the information available from the curves:

$$KW = \frac{KWH \times KW}{KWH} \quad \text{(An identity)}$$

Dividing numerator and denominator by KW.

$$KW = \frac{KWH}{KWH/KW} \quad \text{(where KWH = KWH/Mo/Consumer} \times \text{Consumers)}$$

$$= \frac{\text{KWH/Mo/ Consumer} \times \text{Consumers}}{\text{Max. KWH/Mo/KW} \times \text{\% Max.}}$$

$$= \frac{\text{KWH/Mo/Consumer}}{\text{Max. KWH/Mo/KW}} \times \frac{\text{Consumers}}{\text{\% Max.}}$$

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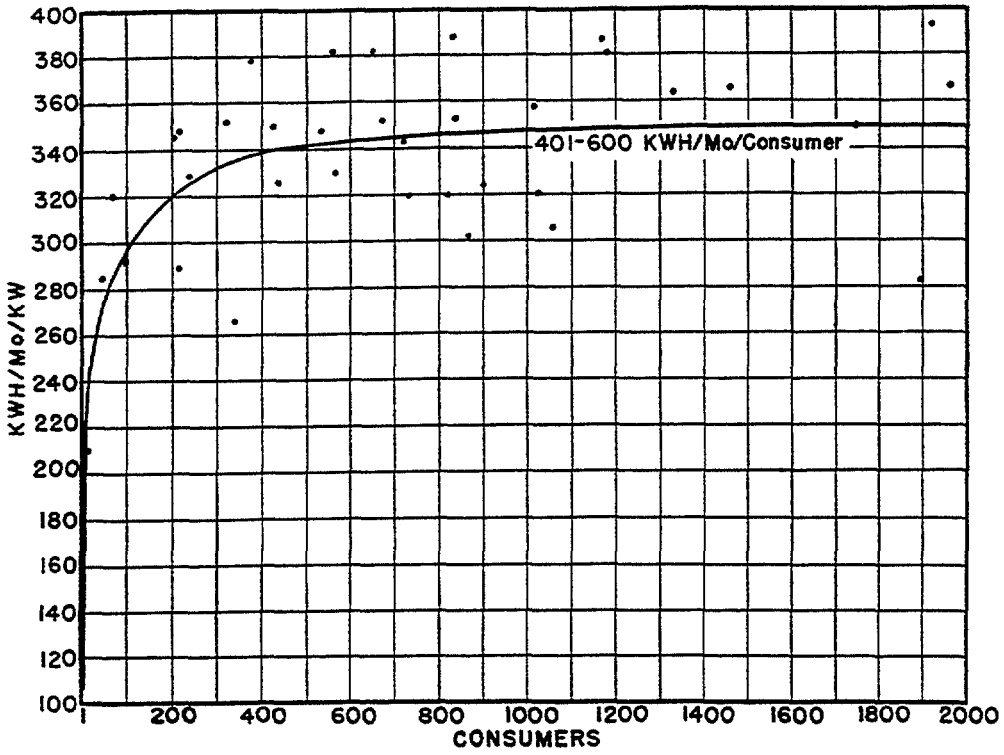

FIG 1 KWH/MO/KW VS CONSUMERS

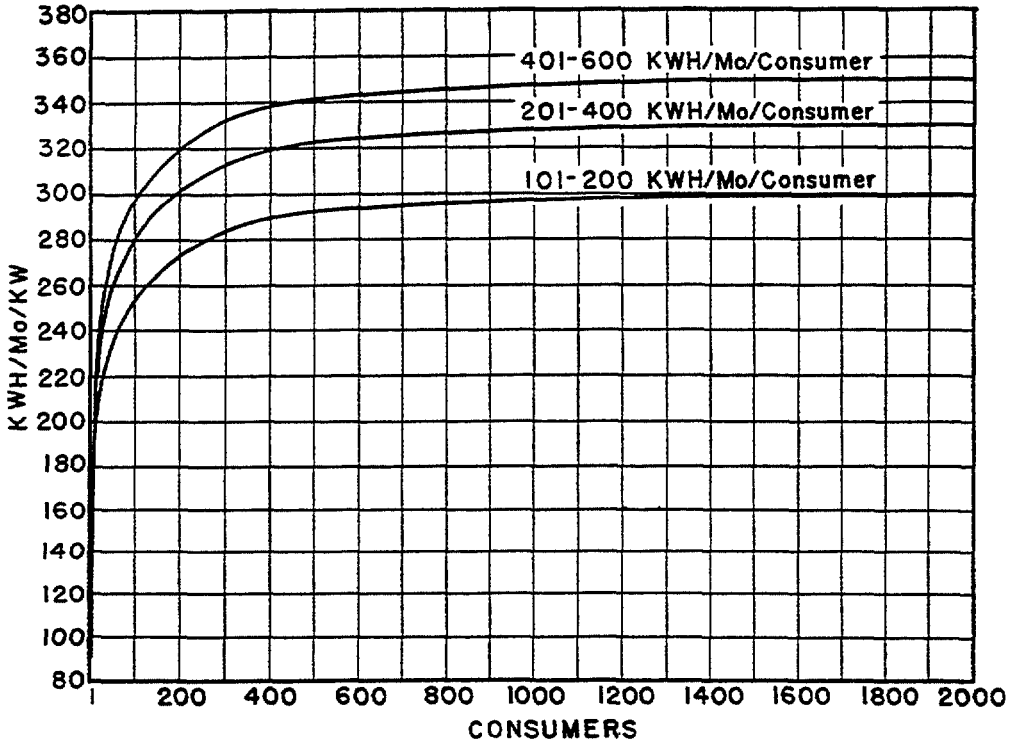

FIG 2 KWH/MO/KW VS CONSUMERS

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The first term has been designated as kwh factor or Factor "B" and the second term as consumer factor or Factor "A". After determining Factor "A" for all numbers of consumers and Factor "B" for all values of kwh, the kw demand for any consumer density and usage may then be calculated by multiplying the two corresponding factors. Factor "A" reflects the improved diversity resulting from an increase in the number of consumers. Factor "B" reflects the improvement in load factor with increased usage, and is the kw demand per consumer to be expected on an average substation having maximum diversity (more than 1400 consumers).

KW demands may be calculated for usages higher than the 2000 kwh/mo/consumer shown in the tables by extending the curve for Factor "B" which is a straight line on log-log paper as shown in Figure 4.

Four methods of calculating demand have been prepared. These are all based upon the curves for Factors "A" and "B" and give approximately the same results.

Method 1: The use of Consumer Factor "A" and KWH Factor "B" from the tables - multiplying the factors gives the demand.

Demand = (Factor "A") (Factor "B")

Method 2: A nomogram has been included in this bulletin for convenience. The divisions on the left-hand scale of the nomogram represent the log of Factor "A" corresponding to the number of consumers, the divisions on the right-hand scale represent the log of Factor "B" corresponding to kwh/mo/consumer; and the center scale represents log Factor "A" + log Factor "B" found by placing a straightedge from "A" to "B". In this way Factor "A" and Factor "B" are multiplied by adding their logarithms.

Method 3: For use with computers it is necessary to provide equations for Factors "A" and "B" to conserve memory space. The following equations may be used for this purpose:

$$\text{Factor "A"} = C(1 - .4C + .4(C^2 + 40)^{\frac{1}{2}})$$

Where C = number of consumers

(This equation is not exact but closely approximates the curve of Factor "A".)

$$\text{Factor "B"} = .005925(\text{KWH/Mo/Consumer})^{.885}$$

(This is the equation of the line in Figure 4)

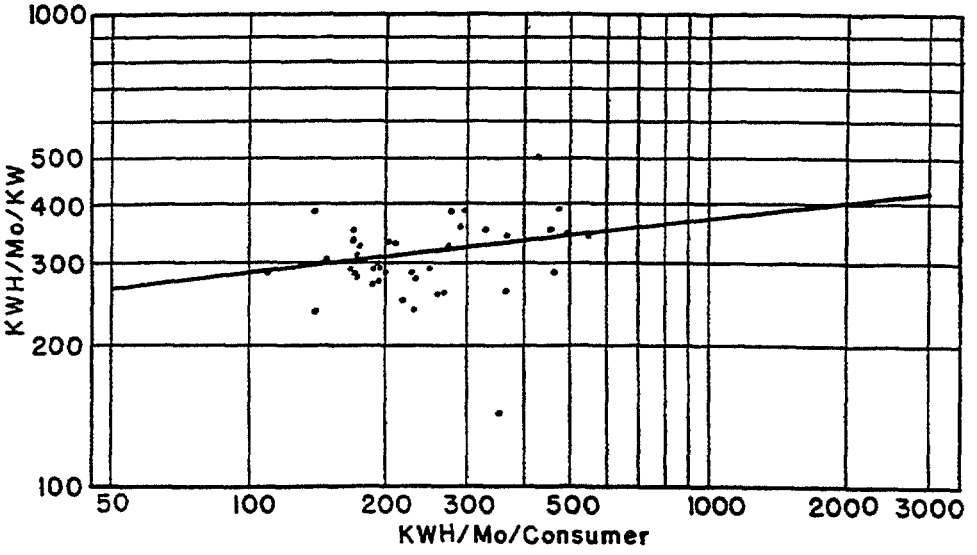

FIG 3 KWH/MO/KW VS KWH/MO/CONSUMER
(For 1400 consumers or more)

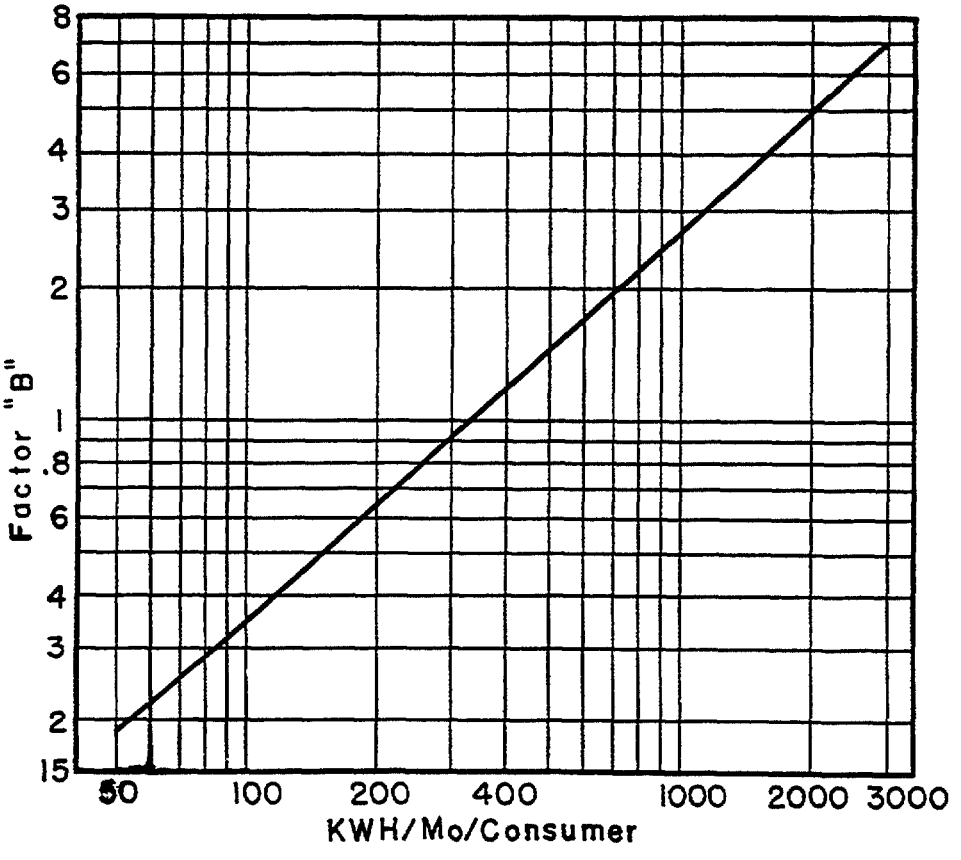

FIG 4 KWH FACTOR (Factor "B")

Method 4: Average demand may be obtained directly from the demand tables. To use these tables, locate the table marked with the proper KWH monthly usage, find the number of consumers in the column marked NO. CONSUMERS, and read the demand in the column marked DEMAND IN KW.

IV. ADJUSTMENT FOR DIFFERENCE IN LOAD FACTOR

As stated in the preface, the demand tables are based on the average system, and some systems will deviate from the average because of load factor. If the load factor and diversity are expected to continue to bear the same relationship to the average, the tables may be easily adapted to the particular system. Three approaches to load factor adjustment are compared as follows·

Given: Present values = 254 kw
500 consumers
200 kwh/mo/consumer

To find· Table, multiplying factor, or shift in Factor "B" curve required for the same area with a usage of 600 kwh/mo/consumer.

Example 1

A demand of 254 kw for 500 consumers is found in the table for 150 kwh/mo/consumer rather than the table for 200 kwh/mo/consumer which indicates that the system has a better load factor than the average system. When the usage reaches 600 kwh/mo/consumer the table to use is found by the ratio:

$$\frac{200}{150} = \frac{600}{x}$$

Solving for x, the proper table to use is the one for 450 kwh/mo/consumer.

Example 2

For 500 consumers and 200 kwh/mo/consumer, the load factor from the tables on page 16:

$$\frac{\text{Consumers} \times \text{KWH/Mo/Consumer}}{\text{KW} \times \text{Hours}} = \frac{500(200)}{328(730)} = 41.8\%$$

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The actual load factor equals:

$$\frac{\text{Consumers} \times \text{KWH/Mo/Consumer}}{\text{KW} \times \text{Hours}} = \frac{500(200)}{254(730)} = 54.0\%$$

$$\text{Multiplying factor} = \frac{41.8}{54.0} = 0.775$$

$$\text{or} = \frac{254}{328} = 0.775$$

Example 3

Consumer factor (Factor "A") does not change but kwh usage factor (Factor "B") changes with load factor. Therefore, adjustment may be made by drawing a Factor "B" curve for the particular system parallel to the average curve.

For 500 consumers, Factor "A" = 512 (p. 46)

$$\text{Factor "B"} = \frac{\text{KW}}{\text{Factor "A"}} = \frac{254}{512} = .496$$

A straight line through the point for KWH/Mo/Consumer = 200 and Factor "B" = .496 drawn parallel to the average curve is the Factor "B" curve for this system.

Comparison of kw demand found in each example for 5000 consumers.

Example 1

Using the table for 450 kwh/mo/consumer, the demand for 5000 consumers = 6600 kw.

Example 2

The table for 600 kwh/mo/consumer shows a demand of 8500 kw. Applying the multiplying factor, the corrected demand equals:

$$8500 \text{ kw} \times 0.775 = 6600 \text{ kw}$$

Example 3

The new Factor "B" curve drawn as mentioned above shows this factor to be 1.32 for 600 kwh/mo/consumer.

For 5000 consumers, Factor "A" = 5000
Factor "A" × Factor "B" = 5000 × 1.32 = 6600 kw

V. COMPARISON OF DEMAND CURVES 1939-1955

The curves prepared in 1939 and 1949 plotting KWH/Mo/KW vs. Consumers are compared in Figure 5 with the 1955 curve for the same usage value. Fifty kwh/mo/consumer has been used as a basis for comparison since the 1939 curve was based on this usage. From 1949 to 1955 the maximum kwh/mo/kw shows very little change. This indicates that the addition of new uses for electricity should not appreciably affect estimates made on the basis of present information.

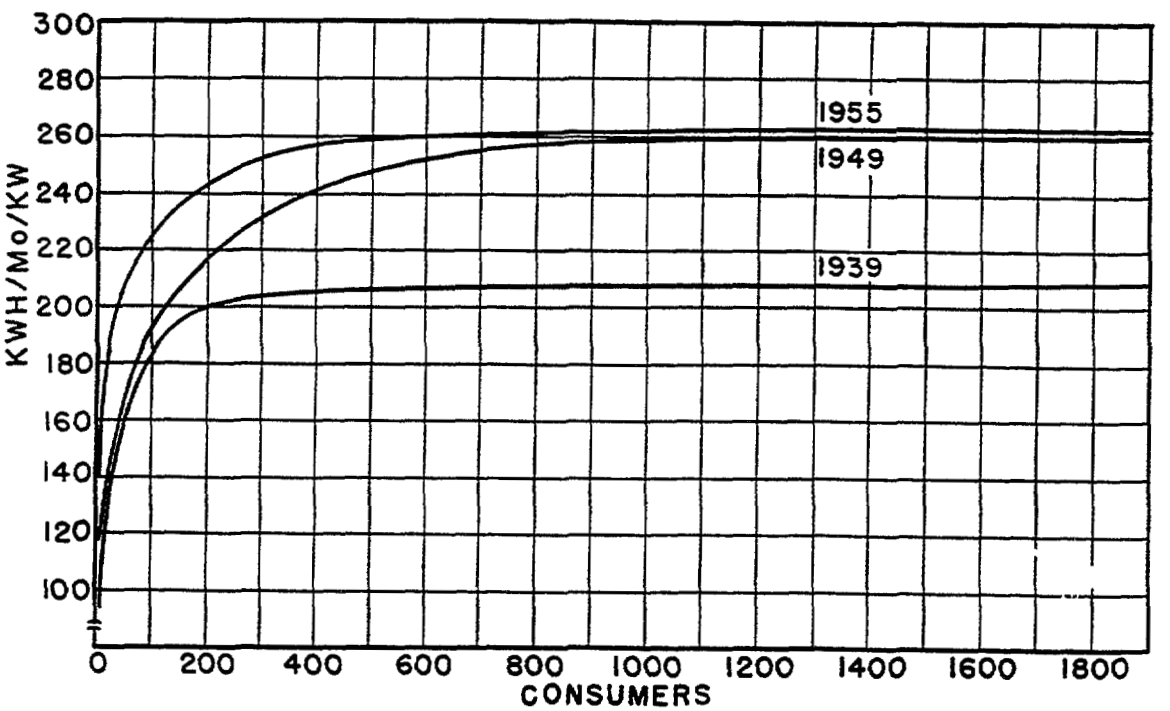

FIG 5 KWH/MO/KW VS CONSUMERS
(For 50 KWH/Mo/Consumer)

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VI. CONVERSION EQUATIONS

Those who may wish to relate the information in the "Demand Tables" to coincidence factor, diversity factor, and average undiversified individual consumer demand may do so by use of the following equations:

$$\text{Coincidence factor} = \frac{\text{Factor "A"}}{3.29 \times \text{Consumers}}$$

$$\text{Diversity factor} = \frac{3.29 \times \text{Consumers}}{\text{Factor "A"}}$$

$$\text{Avg. KW/Consumer (Undiversified)} = 3.29 \times \text{Factor "B"}$$

Where 3.29 = Factor "A" for one consumer

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DEMAND TABLES

KWH FACTOR
(FACTOR "B")

KWH/MO/CONSUMER	FACTOR "B"	KWH/MO/CONSUMER	FACTOR "B"
50	.189	420	1.24
55	.203	440	1.29
60	.220	460	1.34
65	.237	480	1.40
70	.254	500	1.45
75	.270	525	1.51
80	.286	550	1.58
85	.301	575	1.64
90	317	600	1.70
95	333	625	1.77
100	348	650	1.83
110	.379	675	1.90
120	.409	700	1.96
130	.439	725	2.02
140	.468	750	2.08
150	.497	775	2.14
160	.525	800	2.20
170	.554	825	2.26
180	.583	850	2.32
190	.612	875	2.38
200	.641	900	2.44
210	.669	925	2.50
220	.697	950	2.56
230	.726	975	2.62
240	.755	1000	2.68
250	.784	1100	2.92
260	.810	1200	3.15
270	.836	1300	3.39
280	.864	1400	3.62
290	.893	1500	3.84
300	.923	1600	4.07
320	.972	1700	4.29
340	1.03	1800	4.51
360	1.08	1900	4.73
380	1.14	2000	4.95
400	1.19		

NOTE The above table may be plotted as a straight line on log-log paper.

DEMAND TABLES

50 KWH/MO/CONSUMER

FOR USE WITH VOLTAGE DROP STUDY

NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW
5	1 79								
6	2.04								
7	2 29								
8	2 55								
9	2 80								
10	3 04								
11	3 29	62	14 5	255	51 4	820	157	3100	586
12	3.53	64	14 9	260	52 2	840	161	3200	605
13	3.80	66	15 3	265	53 3	860	165	3300	624
14	4.04	68	15 7	270	54 2	880	168	3400	643
15	4 29	70	16 1	275	55 0	900	172	3500	662
16	4 53	72	16 6	280	55 9	920	176	3600	680
17	4 78	74	17 0	285	56 9	940	180	3700	699
18	5 03	76	17 4	290	57 8	960	184	3800	718
19	5.25	78	17 7	295	58 6	980	187	3900	737
20	5 52	80	18 1	300	59 5	1000	191	4000	756
21	5.75	82	18.6	310	61 4	1050	200	4100	775
22	5 99	84	18 9	320	63 3	1100	209	4200	794
23	6 20	86	19 3	330	65 0	1150	219	4300	813
24	6 41	88	19 7	340	66 9	1200	228	4400	832
25	6.60	90	20 2	350	68 8	1250	237	4500	851
26	6 80	92	20 6	360	70 5	1300	246	4600	869
27	7.03	94	21 0	370	72 4	1350	256	4700	888
28	7.35	96	21 4	380	74 3	1400	265	4800	907
29	7 47	98	21 7	390	76 2	1450	274	4900	926
30	7 69	100	22 1	400	77 9	1500	284	5000	945
31	7 92	105	23 1	410	79.8	1550	293	5100	964
32	8.15	110	24 2	420	81 6	1600	302	5200	983
33	8 37	115	25 1	430	83 5	1650	312	5300	1002
34	8.58	120	26 1	440	85 4	1700	321	5400	1021
35	8.81	125	27 0	450	87 3	1750	331	5500	1040
36	9 02	130	28 0	460	89 2	1800	340	5600	1058
37	9 24	135	28 9	470	90 9	1850	350	5700	1077
38	9.45	140	30 1	480	92 8	1900	359	5800	1096
39	9 68	145	30 8	490	94 7	1950	369	5900	1115
40	9.88	150	31 8	500	96 8	2000	378	6000	1134
41	10 1	155	32 7	510	98 7	2050	387	6200	1172
42	10 3	160	33 6	520	101	2100	397	6400	1210
43	10.5	165	34 6	530	102	2150	406	6600	1247
44	10 7	170	35 5	540	104	2200	416	6800	1285
45	10 9	175	36 5	550	106	2250	425	7000	1323
46	11 2	180	37 4	560	108	2300	435	7200	1361
47	11 4	185	38 4	570	110	2350	444	7400	1399
48	11 6	190	39 3	580	112	2400	454	7600	1436
49	11 8	195	40 3	590	114	2450	463	7800	1474
50	12.0	200	41 2	600	116	2500	473	8000	1512
51	12 2	205	42 1	620	119	2550	482	8200	1550
52	12 4	210	43 1	640	123	2600	491	8400	1588
53	12.6	215	44 0	660	127	2650	501	8600	1625
54	12 9	220	45 0	680	131	2700	510	8800	1663
55	13.0	225	45 9	700	135	2750	520	9000	1701
56	13 3	230	46 7	720	139	2800	529	9200	1739
57	13 5	235	47 6	740	142	2850	539	9400	1777
58	13 7	240	48 6	760	146	2900	548	9600	1814
59	13 9	245	49 5	780	150	2950	558	9800	1852
60	14.1	250	50 5	800	153	3000	567	10000	1890

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DEMAND TABLES

75 KWH/MO/CONSUMER

FOR USE WITH VOLTAGE DROP STUDY

NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW	NO CONSUMERS	DEMAND IN KW
5	2 56								
6	2 92								
7	3 27								
8	3								
9	4								
10	4 35								
11	4.70	62	20 7	255	73 4	820	224	3100	837
12	5 05	64	21 3	260	74 5	840	230	3200	864
13	5 43	66	21 9	265	76 1	860	236	3300	891
14	5 78	68	22 5	270	77 5	880	241	3400	918
15	6 13	70	23 1	275	78 6	900	246	3500	945
16	6 48	72	23 7	280	79 9	920	251	3600	972
17	6 83	74	24 2	285	81 3	940	257	3700	999
18	7 18	76	24 8	290	82 6	960	262	3800	1026
[illegible]	7 51	78	25 4	295	83 7	980	268	3900	1053
[illegible]	7 88	80	25.9	300	85 1	1000	273	4000	1080
	8 21	82	26 5	310	87 8	1050	286	4100	1107
	8 56	84	27 0	320	90 5	1100	299	4200	1134
	8 86	86	27 5	330	92 9	150	312	4300	1161
24	9 15	88	28 1	340	95 6	200	326	4400	1188
25	9 42	90	28 9	350	98 3	1250	339	4500	1215
26	9 72	[illegible]	29 4	360	101	1300	352	4600	1242
27	10.0		30.0	370	103	1350	365	4700	1269
28	10 5		30 5	380	106	1400	378	4800	1296
29	10 7		31 1	390	109	1450	392	4900	1323
30	11 0		31 6	400	111	1500	405	5000	1350
31	11 3		32 9	410	114	1550	419	5100	1377
32	11 6		34 6	420	117	1600	432	5200	1404
33	12 0		35 9	430	119	1650	446	5300	1431
34	12 3	120	37 3	440	122	1700	459	5400	1458
35	12 6	125	38 6	450	125	1750	473	5500	1485
36	12 9	130	40 0	460	127	1800	486	5600	1512
37	13.2	135	41 3	470	130	1850	500	5700	1539
38	13 5	140	42 9	480	133	1900	513	5800	1566
39	13 8	145	44 0	490	135	1950	527	5900	1593
40	14 1	150	45 1	500	138	2000	540	6000	1620
41	14.4	155	46	510	141	2050	[illegible]	6200	1674
42	14 7	160	48	520	144	2100	[illegible]	6400	1728
43	15 0	165	49.4	530	146	2150	[illegible]	6600	1782
44	15 3	170	50 8	540	149	2200	594	6800	1836
45	15 6	175	52.1	550	151	2250	608	7000	1890
46	15 9	180	53 5	560	154	2300	621	7200	1944
47	16 3	185	54 8	570	157	2350	635	7400	1998
48	16 6	190	56 2	580	160	2400	648	7600	2052
49	16 8	195	57 5	590	162	2450	662	7800	2106
50	17 1	200	58.9	600	165	2500	675	8000	2160
51	17 5	205	60 2	610	170	2550	689	8200	2214
52	17 7	210	61.6	[illegible]	176	2600	702	8400	2268
53	18.0	215	[illegible]	[illegible]	181	2650	716	8600	2322
54	18 4	220		[illegible]	187	2700	729	8800	2376
55	18 6	225		700	193	2750	743	9000	2430
56	19 0	230		[illegible]	198	2800	756	9200	2484
57	19 2	235		[illegible]	203	2850	770	9400	2538
58	19 5	240		760	208	2900	783	9600	[illegible]
59	19 9	245		780	214	2950	797	9800	[illegible]
60	20 1	250	1	800	219	3000	810	10000	2700

UNDERSTANDING THE LANGUAGE

This section is designed to help our readers better understand some of the more common utility terms For additional information on any of the topics discussed, please refer to *Public Utilities Reports Guide* This guide is available through the Company Library

A

Accelerated Cost Recovery System (ACRS) - Enacted by Congress in 1981, this is a method of writing off the cost of property over an arbitrary time period not based on the concept of useful life

Accelerated Depreciation - The procedure of taking larger depreciation allowances in the first years of property service and much lower allowances in the final years of useful life

Accounting System - A systematic form of records used by a business to provide the factual measure of assets, liabilities, net worth, income, revenues, expenses, and earnings

Accrued Asset - *An asset currently earned but not yet received*

Accrued Depreciation - *Amount of depreciation to date*

Accrued Liability - *An obligation incurred but not yet payable*

Alternating Current (AC) - *An electric current which reverses its direction of flow periodically (In the United States this occurs 60 times a second — 60 cycles or 60 Hertz)*

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Amortize *- Spreading a nonrecurring expenditure over a period of years to avoid distortion or unfair impact*

Ampere *- Unit of measurement of electric current, analogous to cubic feet of water flowing per second*

Antitrust Laws *- Laws designed to maintain competition in our economy*

Arbitration *- The submission of a dispute to a third party or a board of arbitrators for settlement The ruling by arbitration is binding on both union and management*

Asset *- Property or property rights of a business reported in the balance sheet*

Authorized Capital *- The amount of stock authorized for issuance by a corporation in its charter*

B

Balance Sheet *- Accounting records showing at any one time the assets, liabilities, and net worth of a business*

Base Rate *- That portion of the total electric rate covering the general costs of doing business unrelated to fuel expenses*

Blackout *- A complete interruption of electric service to a large area, usually caused by a failure of major generating equipment*

Board of Directors *- The policy-setting group to whom utility company executives report*

Bond *- A certificate bearing a promise to pay interest and repay principal of borrowed funds*

Book Costs *- Original cost of property, as reflected in utility company records*

Book Value *- A company's assets less its liabilities divided by the number of shares of stock outstanding at any given time*

Bottom Line *- Net result of a business or other profit or loss operation*

British Thermal Unit (Btu) *- Quantity of heat necessary to raise one pound of water one degree Fahrenheit at sea level pressure*

Brownout *- A reduction in the voltage of power supplied to customers resulting*

from insufficient supply of power to match demand

Bulk Power Transmission *- The transport of large amounts of electricity at high voltages, usually from one utility to another, through high-voltage transmission lines*

Busbar *- A large, rigid conductor (often a metal bar or tube) Busbars are usually used in substations to feed power to two or more circuits*

C

Cable *- A fully insulated conductor that can be installed overhead or underground*

Capacitor *- A device which maintains or increases the voltage of transmission and distribution lines Capacitors are installed in substations and on poles*

Capacity *- The load for which a machine, apparatus, station or system is rated*

Capital *- The net dollar investment in a business enterprise, or the physical facilities (plant machinery, equipment, fuel, etc) used to produce an economic good or service*

Capital Stock *- Common voting stock ownership securities of a corporation issued and outstanding*

Capitalization *- The amount of the face or stated value of the securities issued by a corporation*

Circuit *- A continuous system of conductors and associated equipment providing a path of electricity*

Circuit Breaker *- A switch (located in substations) that automatically disconnects power to a circuit in the event of a fault condition*

Class Account *- A common practice of combining a large number of like-kind assets in a group for purposes of depreciation accounting*

Class Life Asset Depreciation Range System (CLADR) *- Established by the Treasury Department in 1971, this system set revised guidelines for the useful life of various classes of property*

Cogeneration (Cogen) *- The simultaneous production of electric energy and useful thermal energy (steam) for industrial, commercial heating or cooling purposes*

Collective Bargaining Process *- The union functions as a representative of the*

employees in negotiating a written agreement which serves as the contract between labor and management

Commercial Customers *- Customers who use electricity for heating, cooling, appliances, and industrial equipment, in settings ranging from small retail stores and offices to large retail outlets, industrial plants, and high-rise office buildings*

Commission *- An agency of government usually composed of three or more members charged with specified duties, functions, and responsibilities*

Common Stock *- Same as Capital Stock*

Comparable Earnings *- Measurement of the rate of return by comparing one company's earnings with those of other enterprises*

Competition *- Freedom of economic choice in buying, selling, or exchange of goods and services*

Conductor (electric) *- Materials which allow their electrons to be easily transferred (A wire, cable, busbar, rod, tube, etc , which serves as a path for electrical flow)*

Conglomerate *- Diversification into entirely unrelated lines of business*

Conservation *- The wise use of resources either by reducing energy-consuming activities, or more efficient use of energy*

Conservation Programs *- Utility programs designed to reduce total energy usage on a utility's system by improving the efficiency with which energy is used*

Cooling Towers *- Structures designed to dissipate waste heat from thermal power plants*

Cooperative *- A legal form of business similar to a corporation, except that ownership is vested in members rather than stockholders, and benefits are in the form of products or services rather than profits*

Corporate Plan *- The document produced through the strategic planning process which identifies the company's goals and strategies for achieving those goals*

Corporation *- An artificial personality, created by law to enable a business or other enterprise to be carried out with limited liability to its owners and unlimited tenure independent of the lives of the owners*

Corporation Charter *- A grant of authority from a state for a business to exist as a*

corporation stating its powers purposes, and rights

Cost *- The amount or value of goods and services needed to acquire property or other rights They may be fixed or variable according to time or conditions*

Cost of Capital *- The costs incurred in obtaining capital (by the sale of stocks or bonds) needed to go into business and stay in business*

Cost of Service *- The dollar amount or total sum required to produce any given utility service*

Coverage Ratio *- Measurement of a utility's ability to cover its interest payments from net earnings*

Current Asset *- Property and property rights which are used in present operations of a business (such as cash inventory)*

Current Liability *- A liability obligation presently due and payable within a period of approximately one year*

Current Replacement Value *- An appraisal of property in terms of current prices*

Customer Costs *- Expenses especially incurred for any given customer as such, independent of quantity of service used They include such things as billing meter reading etc*

Customer Service *- Activities by a utility company on behalf of its customers which are in addition to the supplying of the utility's metered or measured service*

D

Debt, Long-term *- Borrowed funds with a maturity (repayment date) occurring far in the future*

Decommissioning *- The safe and orderly permanent shutdown of utility plants (usually nuclear power plants)*

Deferred Credits *- Expenses incurred during the present accounting period but properly chargeable to a later period*

Demand *- The total amount of electricity required at any given time by a utility's customers*

Demand Charges *- A separate service charge based upon the demand for service imposed by a particular customer*

Demand Costs *- Costs incurred to meet customer demands for service,*

independent of the quantity of service used or of the number of customers served Largely related to investment in plant and facilities

Demand-Side Management Programs *- Utility programs designed to shift loads away from periods of high demand, thereby improving system load factors*

Depletion *- Closely related to depreciation, this refers to the actual physical consumption of property (e g , a coal deposit)*

Depreciation *- The wearing out or loss of service value of property used in business operations*

Depreciation Expense *- The annual allowance for the depreciation of property representing that portion that has been used up during the previous twelve months*

Depreciation Reserve *- The paper account which represents the accumulation of yearly allowances for depreciation expense The reserve is viewed as an asset and indicates that funds are (in theory) being set aside*

Deregulation *- The relaxation of controls over business operations*

Differential Pricing *- A practice of having varied rate schedules for different classes of service in order to spread service costs fairly or encourage special classes of service use*

Direct Current (DC) *- Electricity that flows continuously in one direction*

Discounted Cash Flow *- Method of determining fair rate of return to investors assuming that stock price is the present value of future income Investors' future cash flow is discounted to account for present value*

Dismantlement or Decontamination *- A method of decommissioning a nuclear power plant whereby all radioactive materials are removed and disposed of so that unrestricted use can be made of a plant site*

Distribution Line *- Any line operating at less than 69,000 volts used to supply customers*

Distribution Transformers *- Distribution transformers reduce voltage from primary to secondary distribution lines and can be found on poles or platforms*

Diversification *- The practice of engaging in more than one line of business in order to allocate resources better*

Diversity Factor *- A measure designed to show variations in time of use of service by different customers or classes of customers*

Dividend *- A payment or distribution of a corporation's earnings to its stockholders*

Dividend Payout Ratio *- A measure of how much of a company's earnings are paid to shareholders, or how well the dividend is covered by the company's earnings*

Dividend Yield *- Financial ratio determined by dividing the dividends paid per share by the price of the stock It is an indication of the company's normalized earning power*

E

Earnings *- Those funds remaining from income once all expenses are paid*

Earnings per Share *- A measure of a company's profitability calculated by dividing income available for common stock by average shares outstanding*

Easement *- The purchase of the right to use land for a limited purpose with another person retaining ownership*

Elasticity of Demand *- The degree to which demand will vary with a change in price*

Electric Reliability Council of Texas (ERCOT) *- A voluntary organization of electric power producers in Texas established to maintain reliable service through cooperative exchanges of power*

Electricity Generator *- A machine which converts mechanical energy to electrical energy*

Embedded Cost *- An historical cost, or a cost that was incurred in the past*

Employee Stock Ownership Plan *- A contribution plan that is a stock bonus and/or money contribution plan that invests primarily in employer securities*

Energy Costs *- The variable costs connected with plant operation, primarily fuel*

Environmental Controls *- Programs designed to build and operate facilities in such a way as to preserve a healthy environment and conform with aesthetic, historic, and recreational patterns established within the service area*

Exempt Wholesale Generators (EWGs) *- Independent power producers who generate power and sell it on a wholesale basis and who are exempt from the restrictions imposed by the Public Utility Holding Company Act This new class of power producers was created by the National Energy Policy Act of 1992*

Expenses *- Charges incurred in operating a business such as wages, taxes, materials, supplies, etc*

F

Fair Return *- A legal concept of the amount of earning to be allowed a utility company*

Fair Value *- A legal concept of the value of a utility's property for rate-making or other purposes*

Federal Energy Regulatory Commission (FERC) *- An agency within the Department of Energy (DOE), FERC regulates virtually all facets of electric and natural gas production, transmission, and sales when they are conducted between states The National Energy Policy Act of 1992 gave FERC authority to mandate wholesale wheeling, regardless of whether interstate commerce is involved*

Financing Incentive Programs *- Programs designed to encourage customer conservation efforts, utilizing such tools as grants, rebates, low-interest loans, and no-interest loans*

Firm Demand *- A priority for supply of utility service in any amount at any time, as compared with other uses which may be deferred or interruptible*

Fixed Assets *- Assets represented by plants and equipment*

Fixed Costs *- Annual costs attached to ownership, such as depreciation, taxes, insurance, cost of money, and maintenance*

Flat Rate *- A rate schedule that provides for a specified charge irrespective of the quantity of service used*

Fly Ash *- Small particles of airborne ash produced by the burning of fuels*

Forced Outage Rate *- An indication of the percentage of time a power generating unit, transmission line, or other energy facility is forced out of service for emergency reasons This rate can be used in describing a facility's reliability*

Fossil Fuels *- Fuels (including coal, oil, and natural gas) formed by the decay and alteration of the remains of prehistoric plants and animals*

Fringe Benefits *- Benefits for employees in addition to their wages, such as providing insurance, pensions, vacations with pay, and the like, the cost of which is borne in whole or in part by the employer*

Fuel Adjustment Clause *- A provision for adjustments in rates based upon changes in the price of fuel used to generate electricity*

G

Grid *- The network of transmission lines and related control equipment that carries electricity from the generation source to the distribution system of a local utility*

Gross Income *- All revenue collected the starting point for all income tax calculations*

Ground *- When one or more conductors contact the earth causing electricity to flow out of the circuit into the earth*

H

Holding Company *- An organization not directly engaged in the operation of any business, but which owns the stock of other companies*

I

Incentive Rates *- Promotional rates which attempt to increase sales to high elasticity customers.*

Income *- Revenues received from sales and other operations of a business*

Income Statement *- Records of the business showing the flow of funds in the business over a period of time*

150

Incremental Costs *- Extra expenses incurred from the production of an additional quantity of service*

Independent Power Producers (IPPs) *- Non-regulated companies that specialize in the development of generating plants to produce and sell electricity Under present laws, they can only sell power to utilities who must purchase any excess electricity produced by these companies Some IPPs also operate cogeneration plants which use a single source of fuel to produce both steam and electricity*

Industrial Customers *- Customers who use electricity for heating, cooling, appliances, and industrial equipment in industrial plants*

Insulation *- The protective material covering the electric wire Rubber or polyethylene are commonly used*

Insulator *- The support used to insulate the conductors from the pole or tower*

Interest *- A payment made for the use of borrowed funds*

Interim Rates *- Emergency rates granted by commissions while a rate case is being decided*

Interruptible Rates *- Rates offered to customers who are willing, upon the utility's request, to have their service interrupted*

Investor *- One who makes funds available to a corporation by purchase of its securities*

Investor-Owned Utility *- A utility company owned and operated by investors to serve the public*

Issue Advertising *- An advertising technique which focuses on specific issues*

K

Kilovolt (kV) *- A measure of electric energy equal to 1,000 volts*

Kilowatt (kW) *- A measure of electric energy equal to 1,000 watts*

Kilowatt-hour (kWh) *- A measure of electricity consumption equivalent to the use of 1,000 watts of power over a period of one hour*

L

Labor Union *- An organization of persons, usually wage earners, united for the purpose of attaining common goals or benefits*

Liability *- An obligation due to another*

Load *- The total demand for service on a utility system at any given time*

Load Factor *- A measure of the degree to which physical facilities, such as power plants, are being utilized, the ratio of average output to peak output*

Long-term Liabilities *- Liabilities spread out over several accounting periods*

M

Makeup Water *- Water to replace that lost through evaporation and other factors*

Market Value *- The price at which stock is presently selling on the stock market*

Mediation *- The activity of a third party who is called in to assist labor and management settle a dispute*

Megawatt (MW) *- One thousand kilowatts*

Monopoly *- Absence of competition in any economic relationship*

Municipal Customers *- Municipal customers are city accounts (one customer account for each city) These customers use electricity for street lights*

N

Net Income *- The excess of total revenues over total expenses*

Net Worth *- Records of a business showing the net investment or new ownership (equity) interest in the business remaining after liability obligations are balanced against assets*

Non-Utility Generator (NUG) *- Any generator of electrical power other than a utility This includes self-generators, cogenerators, independent power producers, and/or exempt wholesale generators*

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O

Off-Peak Rates *- Special rates, usually quite low, for service supplied during periods of relatively low demand, such as during early morning hours, Sundays, holidays, etc*

Operating Company *- A company directly involved in the operation of the business which finances diver fied activities on a centralized basis*

O ating Costs *- Expenses incurred in a business rising fro or directly related to producing the service*

Outage *- An isolated temporary loss of tricity generally caused by trouble o rring in the generation, transmission, or distributio facilities*

P

Parent Company *- Owns the stock of one or more subsidiaries*

Peak D and *- The maximum amount of el icity required to supply customers*

Peak Load *- The maximum load consumed or produced in a stated period of time*

Physical Depreciation *- Loss of service usefulness or life due to wear and tear from use or other causes, such as rust or rot*

Pole-Mounted Transformer *- The transformer mounted on a pole which steps down primary distribution voltage for use by individual customers*

POOLCO *- A proposal currently under consideration in California, which would set up the equivalent of a commodity market-type organization for purchasing power generation to mee tem load requirements Low bidders would be dispatched first, while companies submitting higher bids would risk not selling power into the grid and therefore possibly incurring losses Under a POOLCO concept, spot prices based on marginal costs (i e , variable fuel and operating costs) would become the market price and a given generator's profitability would be dependent on its ability to produce power at or below that price*

Portfolio *- A group of varying securities held by an investor*

Power Brokers *- Regional entities which coordinate the dispatch, purchase, and sale of bulk power among utilities*

Power Pool *- Interconnected electrical systems planned and operated to supply power in the most reliable and economical manner for the combined load requirements and maintenance programs*

Preferred Stock *- Ownership interests in a corporation which have been granted a preference, usually in the distribution of dividends before payment of dividends to common stockholders*

Primary Distribution Lines *- These lines come out of the substation carrying electricity at levels ranging from 12,000 to 34,500 V*

Profit *- Remaining income after business expenses are paid*

Public Service Advertising *- Designed to benefit the public and indirectly build goodwill for the sponsoring utility Advertising used to encourage conservation of energy is public service advertising.*

Public Utility *- A business enterprise rendering a service considered essential to the public and, as such, subject to regulation in the public interest, usually by statutory law*

R

Rate of Return *- This is what investors receive for use of their money Overall rate of return is applied to the rate base and includes the weighted cost of long- term debt and the weighted cost of preferred stock as well as the allowed return on common equity*

Recloser *- A switch which functions like a circuit breaker, protecting primary circuits from fault conditions A recloser will automatically restore the circuit in the event of a temporary fault. (Temporary faults can be caused by such things as a tree branch brushing lines)*

Regulated Utilities *- Utilities distinguished as being a class of business with deep public interest and therefore, subject to regulation (Public utilities are further distinguished in that, in most jurisdictions, it is considered desirable for them to operate as controlled monopolies As such, they are obligated to charge fair, non-discriminatory rates and to render safe, reliable service to the public on demand. In return, they are generally free from substantial*

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direct competition and are permitted, although not assured, a fair return on investment and recovery of reasonable operating costs)

Regulator *- A type of transformer which maintains constant voltage on main distribution lines (feeders) as customers' demand for electricity changes*

Relays *- Sensitive instruments which trigger switches to interrupt circuits when a fault is detected*

Resale Customers *- Customers who purchase electricity to sell to their own retail customers*

Residential Customers *- Customers who use electricity for heating, cooling, household appliances, and lighting in a private dwelling setting (home or apartment)*

Responsive Reserve *- With the construction of four nuclear units in the state of Texas (each greater than 1,000 MW of capacity), the Electric Reliability Council of Texas (ERCOT) decided to review the spinning reserve guidelines Since the two largest units would now closely approximate 10% of the average ERCOT load the generating plants in each control area would not only be required to have available spinning reserve, but would also need to provide the reserve quickly to alleviate conditions arising from the large unit trips ERCOT defined the "responsive reserve" requirements as follows The "responsive reserve" contribution of a unit is the minimum of (1) 20% of its rated capacity limit, or (2) the difference between the rated capacity and the actual generation — whichever is lower Distributing the responsive reserve across many generating units increased the system responsiveness by allowing the system to have more units participating in alleviating system disturbances ERCOT assigns "responsive reserve" to its ten control areas based on a formula which takes into account (1) the control area's load, (2) the control area s largest generating unit on-line, and (3) the sum of the two largest units in the entire ERCOT region Once allocated, each control area will maintain its spinning reserve throughout its planning and operation for the day*

Retail Customers *- Customers who purchase electricity to use themselves*

Return *- Amount of earnings after expenses are deducted from revenues, which may be expressed as a percentage of fair value or the rate base*

S

Secondary Circuit *- The distribution circuit on the low voltage side of a transformer (usually 120/240 volts)*

Secondary Distribution Lines *- These lines carry lower voltage electricity for use in homes and small businesses Residential voltage levels are usually 120 to 240 volts*

Self-Generator *- Customers who provide for their electric power needs through the use of their own generating facilities*

Self-Service/Affiliate Wheeling *- A process by which independent power producers or cogenerators wheel excess power from their generating facility to one of their company's "affiliated" facilities over a utility's transmission lines*

Service Area *- The territory in which a utility company has the right to supply or make available its utility service*

Service Drop *- The lines running from the pole to the customer's house Usually made up of two 120-volt lines and a neutral line from which the customer can obtain either 120 volts or 240 volts of power*

Single Phase Line *- A conductor capable of serving the needs of residential customers, small commercial customers, and streetlights A single phase line carries a relatively light load as compared to a heavy duty three phase line*

Spinning Reserve *- Electric utilities which are also control areas* are required to maintain an assigned amount of on-line generation reserve that can be made available to a region or pool to respond to such system disturbances as unexpected unit trips or load increases This on-line reserve that is available to meet instantaneous changes in demand is the spinning reserve (*Note· A control area is capable of regulating its generation and interchange schedule to match system load)*

Subsidiary *- A company whose stock is owned by a controlling organization*

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Substation *- A facility (small building or fenced-in yard) containing switches, transformers, and other equipment. Functions performed at the substation include circuit monitoring and voltage adjustments (voltage of electricity is reduced prior to distribution to customers)*

T

Three Phase Line *- A conductor capable of carrying heavy loads of electricity*

Transformer *- Electrical equipment vital to the transmission and distribution systems Used to transform voltage levels to facilitate the transfer of power from the generating plant to the customer (designed to increase or decrease voltage)*

Transmission *- The act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems*

Transmission Access *- The ability of third parties to make use of transmission facilities owned by others to deliver power to another utility*

Transmission Line *- Any line operating at 69,000 or more volts*

Transmission System *- The system that transports electric energy in bulk form, usually in high voltages, from a source of supply to the distribution systems or major parts of the system*

Trip *- The action of breaking a circuit — usually refers to an automatic rather than a manual action*

Turbine *- Equipment used in the generation of electricity which is driven by a working fluid and, in turn, drives the generator*

U

Unbundling *- Establishing prices for the various services provided by a utility (i e , transmission or distribution)*

Useful Life *- The period of time over which property is depreciated, the length of time that property or equipment is expected to last before replacement*

Utility Holding Company *- An investor- owned company that owns one or more public utilities*

V

Value of Service *- A term denoting what the service is worth to a customer (or class of customers)*

Variable Costs *- Those expenses of a business enterprise which vary with changes in volume of output, such as outlays for fuel to generate electric power*

Volt (V) *- The unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch*

Voltage *- A measure of the push or pressure which transmits electricity*

W

Watt (W) *- The electrical unit of power or rate of doing work*

Watt-hour Meter *- A meter designed to measure consumption of electrical energy over a period of time*

Weatherization *- Increasing the thermal efficiency of a structure using such items as caulking, insulation, gaskets, and storm windows and doors*

Working Capital *- The amount of cash required to operate a utility during the interim between the rendition of service and the receipt of payment*