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USAID Eastern Europe Regional Energy Efficiency Project

Regulatory Reform And Energy Sector Restructuring Contract

IMPLEMENTING ENERGY REGULATION IN POLAND: CONCEPTS AND PRACTICES II - ECONOMIC REGULATION

December 9 thru 11, 1996 Warsaw

Prepared for
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Bechtel International Consulting Group

BECHTEL

Implementing Energy Regulation in Poland: Concepts and Practices II--Economic Regulation

Sponsored by USAID

Warsaw, December 9-11, 1996

Training Schedule: Page 1 (Dec. 6 FINAL DRAFT)

<u>December 9, Monday</u>

8.00-9.30	Hotel Vera-Warsaw arrival and orientation	Agnieszka Sosulska
9.30-10.00	Welcome and Program Introduction	Chris Turner (Bechtel/USAID)
10.00-10.30	Update: Progress toward the Energy Law and the ERA	Mirek Duda
10.45-12.30	Session 1: Review of Economic Regulation Principles Multiple objectives of price regulation Who is regulated, and why? Basis for economic regulation: costs, prices, or both? Revenue (or cost) recovery mechanisms	Karl McDermott
12.30-14.00	Lunch and Hotel Check-In	
14.00-15.30	Session 2: The Starting Point--Economic Regulation in Poland Today Electricity, by sub-sector Gas, by sub-sector District Heating	Marek Grzybowski) Andrzej Palega) Andrzej Piwowarski) Witold Cherubin
16.00-17.30	Session 3: Panel Discussion--Charting the Course for Poland Review of tariff transitioning issues Are prices "right" now? How do we know? Social and political issues	Chris Turner) Mirek Duda) Karl McDermott) John Gulliver) Dennis Colenutt) Andrzej Szablewski) Andrzej Palega

18.00 Hosted Dinner

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December 10, Tuesday

9.00-10.30	Session 4: Cost-Based Regulation Accounting costs in tariff development What costs matter? Is profit a cost? Load research, cost classification, allocation Determining a "Revenue Requirement"	Floyd Davis
10.45-12.30	Session 5: Moving Toward Forward-Looking Approaches The time dimension--use of forecasted costs Marginal costs in tariff development Developing incentives for better performance General discussion on cost-based regulation	Chris Turner) Karl McDermott) Floyd Davis
12.30-13.30	Lunch	
13.30-15.00	Session 6: Price-Based Regulation The origins and use of (RPI - X) How price caps work Results: has (RPI - X) been successful?	Dennis Colenutt
15.30-17.00	Case Study 1: Regulation of Regional Electricity Companies in Great Britain The REC Review Working with (or against) OFFER Winners and losers	Dennis Colenutt
17.00-18.00	Open Discussion of Cost-Based and Price-Based Regulation Key issue: availability and "ownership" of information Key issue: getting to the "starting point" Key issue: setting Customer Class revenue targets Key Issue: management incentives vs. management greed	Chris Turner) Karl McDermott) John Gulliver) Floyd Davis) Dennis Colenutt

18.00 Dinner on your own

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December 11, Wednesday

9.00-10:30	Session 7: Introduction to Performance-Based Ratemaking What is an Alternative Rate Plan ("ARP")? How does an ARP compare with C-O-S and (RPI-X)? Why adopt an ARP?	John Gulliver) Cathy Connors
10.45-12.30	Case Study 2: Moving to Performance-Based Ratemaking, Maine, USA Structure of Central Maine's ARP Results under the ARP Lessons learned and challenges for Poland	John Gulliver) Cathy Connors
12.30-13.30	Lunch	
13.30-15.00	Session 8: Critique of Economic Regulation Approaches What makes sense? What doesn't?	Karl McDermott
15.30-16.30	Panel Discussion: Recommendations for Poland For Electricity, by sub-sector For Gas, by sub-sector For District Heating General Discussion	Chris Turner) John Gulliver) Karl McDermott) Dennis Colenutt) Andrzej Szablewski) Mirek Duda
16.30	Conclusion	

Price-based Regulation (RPI, X, and all that)

Dennis Colenutt

n/e/r/a

10 December 1996

Origins of RPI - X

Development of RPI - X came from a desire to reconcile the needs for:

- A stable and less intrusive regulatory regime
- The introduction of effective incentives for efficiency
- A means of coping with high rates of inflation

What is RPI - X?

At its most general the control is of the form:

$$M_t = [1 + (RPI - X)] \cdot M_{t-1} - C_t$$

Where:

M_t	is the maximum average price in year t
RPI	(the retail price index) is a measure of the rate of inflation
C_t	is a year-to-year correction factor
X	is an "efficiency" factor

How Does it Work?

There are a number of key features:

- It provides a methodology for fixing the maximum price level which deals with changing circumstances
- The level set by the formula provides a bench-mark for the utility to beat
- The control is fixed for a reasonably long term, usually 3 to 5 years
- It is non-reopenable by either side (at least in theory, and so far in practice)
- Any additional profit (or loss) enjoyed by the utility during the period is retained

Where is it Applied?

Geographically, it is becoming reasonably widespread:

- The UK was the original proponent, and continues to use it widely
- Adopted in a number of other countries, including Australia, New Zealand, and some South American countries

Sectorally, it has wide application, and in the UK applies to:

- Electricity
- Gas
- Telecommunications
- Water
- Airports

How is it Applied (1)

When used in practice RPI - X has a number of complications:

- Forecasting errors in the RPI or other factors can lead to significant over- or under-recoveries
- Uncontrollable costs such as oil prices cannot be subject to an RPI - X control and so have to be treated differently
- A mix of "outputs" can cause problems and may have to be dealt with by means of weighted averages or baskets of products
- Distortions to incentives can cause problems and need to be dealt with

The consequence is that some formulae can become rather complicated, with other terms such as Y, K, A, etc.

How is it Applied (2)

Key points about methodology are:

- **<u>Not</u> just a case of deciding what is a reasonable efficiency factor and applying it.**

- **Necessary when setting and re-setting to make a thorough examination of:**

  - **the level and breakdown of costs**
  - **valuation of existing assets**
  - **capital investment requirements**
  - **what is a reasonable level of profitability**
  - **the scope for efficiency gains**

- **It may be necessary to set a <u>negative</u> X, that is RPI + X, if there are major capital investment needs or other special factors**

Has It Been Successful (1)

- RPI - X continues to be used in all the cases where it was first introduced
- All prices controls have now been reviewed at least once, most of them twice and some of them three times
- Complaints about excessive profitability have been made, and may have been justified, but these must be viewed in the light of:
  - possibly generous initial setting because of the uncertainties
  - unanticipated efforts and achievements in improving efficiency
  - the subsequent reviews which took away much of the gain.

Has It Been Successful (2)

A number of modifications have been made to the details of the controls, for example:

- using last year's RPI instead of the forecast level
- adding fixed terms instead of terms which depend on the quantity sold
- reducing the extent of pass-through to give some purchasing incentives
- using pre-determined quantity figures instead of actual

Another debate has been about moving towards some profit sharing or sliding scale arrangement, but so far this has not been taken up.

Price Cap or Profitability Cap?

The long-term aim is to control both:

- The control itself applies to the price level, and contains no reference to profits.
- During the period of the control, profits may vary up or down, so within that period there is no active profit control.

But:

- it is the ability to earn additional profits within the period that provides the efficiency incentive, and
- price levels and profits will be corrected during the review at the end of the period of control.

The English RECs' Price Reviews

Dennis Colenutt

n/e/r/a

10 December 1996

What are the RECs?

The 12 Regional Electricity Companies (RECs) are the local electricity utilities. They carry out a number of business activities:

1) operation of the (monopoly) distribution system;
2) regional electricity supply (public electricity supplier);
3) out-of-area electricity supply (second-tier supply);
4) generation;
5) other activities such as retailing, contracting, etc.

What is Regulated?

Only the non-core activities such as retailing and contracting are not subject to regulation, and all of the other activities are subject to separate regulatory provisions:

1) the distribution system is licensed and subject to RPI-X price control and quality controls and performance standards;

2) the public electricity supplier activity licensed together with distribution, and is subject to RPI-X price controls and to performance and other standards;

3) second-tier supply electricity is separately licensed and subject only to broad controls - there are no price controls;

4) generation is separately licensed and is subject to no price controls;

How Are Their Prices Regulated?

- The Office of Electricity Regulation (OFFER) is solely responsible for regulation. It is established as an independent body, and has sole responsibility for issuing and carrying out all necessary administration and amendment of licences conditions.

- Where licences have price controls they consist of:

  - RPI-X price conditions governing overall price and revenue levels;
  - other conditions against cross-subsidy and discrimination.

- Price control conditions have no fixed expiry date. They have provision so that after a set period (3 to 5 years) they may be "disallowed". There is no provision for any re-opening before the end of the period.

What the Law Says (And Does Not Say)

The law (Electricity Act 1989) says that licence conditions, including the price conditions, can only be changed in the following circumstances:

- if OFFER and the licensee both agree to the change;
- where the licensee does not agree the change, only if the question is referred to the Monopolies and Mergers Commission (MMC), and they recommend the change.

However, it needs to be borne in mind that:

- there are no specified procedures as to how changes should be proposed or negotiated, or how agreement should be reached;
- OFFER has a number of obligations, including protection of the financial viability of the licensee.

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The Price Review Timetable

- No timetable is laid down, so OFFER is free to proceed in any reasonable way.

- But, a reference to the MMC takes at least 6 months, so time needs to be allowed for that at the end of OFFER's review process.

- A typical review timetable would therefore be:

October 1995:	Commencement of review
August 1996:	New price control proposals put to the licensee
October 1996:	Deadline for reference to the MMC, if licensee objects to the proposals
April 1997:	Application of new price control

Working with OFFER - The Review Procedure (1)

There is no set format for the review process, but the following would normally be components:

- public consultation, in which OFFER publishes a consultation paper on what it sees as the issues and invites comments from all interested parties;
- a financial and economic review of past performance, and of forecasts for the next period;
- a technical review of performance, of investment plans, and of prospects for efficiency gains;
- development by OFFER of proposals which are then put to the licensee.

Then:

EITHER:	OR:
publication of the proposals for comment;	preparation of terms of reference for an MMC enquiry;
finalisation of the proposals.	finalisation of proposals on the basis of the MMC findings.

Working with OFFER - The Review Procedure (2)

The procedure does <u>not</u> include the following:

- a fixed timetable;
- public hearings;
- judicial-style hearings in which evidence is heard, and witnesses called and cross-examined;
- an appeals process, other than the MMC.

Working with OFFER - The Review Methodologies

- Increasing attention is now focusing on a narrow range of methodological questions, in particular:

  - the valuation of the company assets;
  - depreciation policies;
  - the appropriate rate of return for the companies.

- No agreed methodologies have been established, and there are inconsistencies between regulators, the MMC, and even decisions by the same regulator.

- It is arguable that such methodologies should now be laid down, though there is a trade-off between certainty and flexibility.

The Distribution Review - A Case Study

The following timetable shows the main events in the recent disastrous price review for the English RECs:

September 1993:	OFFER begins review
August 1994:	Outline proposals for new price controls
September 30 1994:	Companies accept new controls
February 10 1995:	Proposed licence modifications published
February 17 1995:	Northern Electric issues defence document
March 7 1995:	OFFER announces possible review of proposals
March 11 1995:	Deadline for comments on proposals
March 24 1995:	OFFER announces a new review
March 31 1995:	Expiry of "Golden Share"
April 1 1995:	Implementation date for new controls
June 1995:	New (tighter) proposals made for price controls.

The Distribution Review - Winners and Losers

The process is intended to balance and protect the interests of shareholders and consumers.

Recent events may have given consumers the impression that OFFER is doing a good job and that their interests are being protected, but:

- companies may be more cautious in future in revealing potential cost savings;
- capital markets have suffered a shock to confidence, and the cost of capital to utilities may in future be higher than it otherwise would have been;
- consumers may, in the long run, pay more;
- OFFER's credibility suffered a serious blow, and may result in reform to the regulatory framework.

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An Overview of American Regulation

Commissioner Karl A. McDermott
Illinois Commerce Commission

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Why Regulation?

- Monopolists have no reason to perform efficiently.
- Monopolists have every reason to exploit the customers.
- Monopolists can use their market power to thwart competition (cross-subsidies to support predatory pricing actions).

The Objectives of Regulation

- To promote efficient production
- To allocate resources fairly and efficiently

In other words, to counteract the monopolists power and force the monopolist to behave as if they operated in a competitive market.

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What is the Basis for Regulation?

- The Competitive Market
  - Competitive pressure to secure the consumers' purchase forces the firm to behave efficiently and to be innovative.
  - In competition the payoff for taking innovating risks is a short-run profit, failure could result in losses or bankruptcy. A natural selection process is at work.

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What is the Basis for Regulation?

- The Competitive Market
  - In the competitive market, prices are ultimately driven to cost. Regulation has employed this idea by basing the rates or prices it allows a utility to change on the "cost of service".
  - Markets rely on the decentralized decision and incentives facing each market participant to reveal what this efficient marginal cost price is. Regulation has attempted to substitute an administrative process to discover the marginal cost price.

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Why Price Regulation?

- Cost-based regulation is really a form of price regulation.
  - Price is the signal to customers of the societal costs of consuming an additional unit of that resource or bundle of resources that go into the goods production. (Do we see the foundation of Marx's labor theory of value lurking in here?)
  - The additional or marginal costs of each additional unit of output must be reflected in prices if resource allocation and production decisions are to be efficient.

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Calculation of "Cost"

- Traditional Approach
  - Calculate the total "prudent" costs of service
    - » "Prudent" implies judgment, judgment often requires comparison to some other hopefully objective, benchmark.
    - » But this begs the question. If you had a reliable benchmark why not just use it to set prices!
    - » This provides the ***Revenue Requirement***

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Calculation of "Cost"

- The revenue requirement is then allocated across the various classes of customers in order to set class revenue requirements and rates for that class.
  - » Revenues and costs differ based on load factor, time of use, (coincident demands), total use among other characteristics.

In the simplest world these cost/revenues are then divided by class total consumption to generate an average cost/price for the class.

Calculation of "Cost"

If all the assumptions used to generate this average cost/price remain true, then charging this price should allow the company to recover its revenues and costs.

The problem here is that nothing ever remains the same and that cost causality is almost never coincident with average cost.

Marginal Cost Concepts

- Cost causality in economic theory is reflected in the marginal cost of production.
  - If it is truly in a natural monopoly environment the marginal cost based price would generate a revenue requirement less than the total costs of providing the services.
    - » $MC < AC$
      - Marginal Cost Calculations are forward looking calculations that do not factor in "embedded" or current fixed costs

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Marginal Cost Concepts

- How are marginal costs and the utilities "prudent" costs reconciled?
  - Marginal Costs are "Marked" Up/Down to recover "Embedded" costs
    - » Ramsey Pricing
      - Must know demand elasticities
    - » Lump-Sum Transfer
      - Charge marginal cost and provide utility with transfer payment
    - » Equal Percentage of Marginal Cost (EPMC)
      - Pro Rates revenue requirement by percent of marginal cost
      - Assumes demand elasticities are same for all classes
      - Easy calculation makes it the most often used

Marginal Cost Concepts

Example: Three Classes R,C, and I

Class	Marginal Cost	% of MC	Revenue Requirement
R	35	54	54
C	15	23	23
I	15	23	23
Total	65	100 %	100

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Marginal Cost Concepts

- Long-run Marginal Costs
  - » Takes all long-run capacity costs into account
- Short-run Marginal Costs
  - » Recognize that plants are dispatched in merit order (i.e. from lowest marginal cost to highest marginal cost).
  - » This approach may produce revenues greater than the total "prudent" costs that we calculated if the system has significant peak load conditions that last for considerable periods of time-long summer peaks or broad daily peaks.
  - » It can also result in under recovery if significant excess capacity exists.

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Rate Design

- Block pricing
  - » Used to recover fixed costs up front. Thus units on the margin can be priced at marginal cost
- Short-run marginal cost pricing
  - » Used to price short-term transactions
- Two-part rates
  - » Normally used to recover a fixed cost so additional units can be priced on the margin
  - » Can be used in tandem with block pricing

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Critique of Traditional Regulation

- Treats input asymmetrically (Averch-Johnson) implying inefficient input choice.
- Self-referential cost analysis
- Potential for x-inefficiency/cost padding
- Slows innovation by controlling depreciation

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Critique of Traditional Regulation

- Potential asymmetric treatment of gains/losses implies no incentive to take risks.
- Closed nature of the system - Actions cause offsetting counter actions. Cannot punish the utility for poor performance.
- Profits tied to sales implies no incentive for conservation.

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Critique of Traditional Regulation

- The primary problem with traditional U.S. regulation is that it employs a static-equilibrium model to determine prices. The world in which those prices are operative is a dynamic-disequilibrium world. As a result traditional regulation works well if you want a snapshot of the utility's situation. It fails to provide appropriate incentives over time as conditions change. Dynamic regulation requires adjustment mechanisms and flexibility so that utilities can respond to change and customers can share in the gains from efficiency and innovation that arise as the utility responds to changing condition.

Quote

- The fundamental principle of economics is that people will pursue their own self interest within a given institutional framework. Goldberg.

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Quote

- ...that the proper role of regulation is that of a substitute for competitive market forces where those forces are weak or absent. The regulator's task then becomes a two-part undertaking: first to determine the rules of behavior that a regulated firm could have been expected to follow if it had operated free of regulation in a market with fully effective competitive forces; second, to constrain the regulated firm to behave as it would in such a competitive market and to circumscribe its behavior no less and no more than this.

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Quote

- Taken together...the first four goals offer effective criteria for judgement. They do so because a well functioning, competitive marketplace tends to achieve all four. Thus, one often hears that the objective of cost-of-service ratemaking is to replicate a competitive marketplace--that is to say, to reproduce the price, profit, output and efficiency levels that would exist were the regulated market in fact competitive and well functioning.

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Quote

- Cost based pricing may create the wrong incentives for firms. If prices allocate total costs, the firms may not have an incentive to minimize total costs.
- Competition seems very well in practice; but it is not so clear how it works in theory.

Quote

- For it is not only lag in regulation which provides incentives and penalties toward improvement. It is lag in the non-regulated world which does the same. If all competition were perfect and all readjustments instantaneous in the competitive world, there would be no financial incentives to change, as Schumpeter has pointed out. The advantage which the innovator gets is time: his competitors cannot imitate him too quickly.

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Cost-Based Regulation

USAID Utility Tariff Workshop
Warsaw, Poland
December 9-11, 1996

Topics to be Covered

- Overall revenue requirements calculation
- Functionalization and classification of costs
- Revenue requirements of the transmission function
- Functionalization, classification and allocation of transmission costs
- Classification and allocation of distribution costs
- Load research

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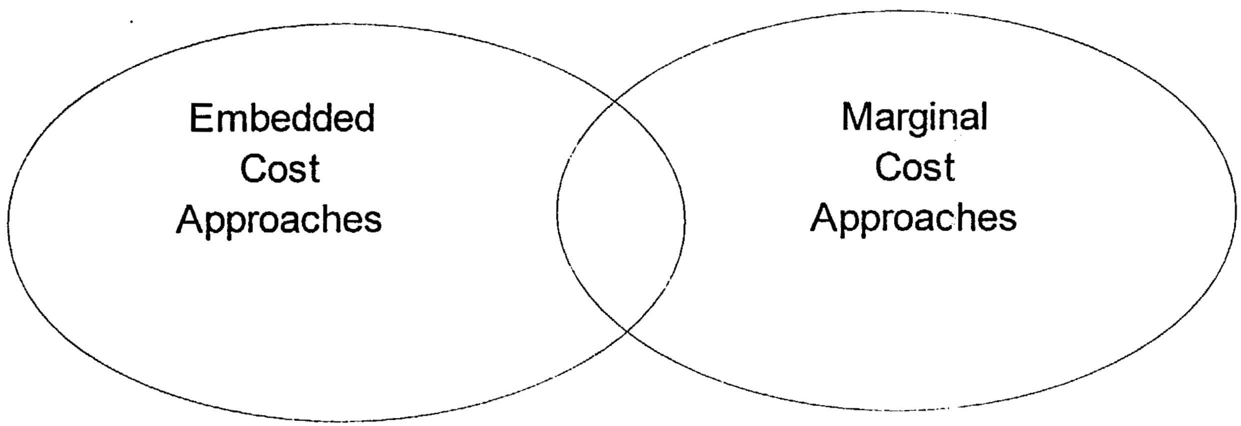
Cost Reflective Tariff Setting Approaches



Definitions

- Embedded costs- past investment and operating costs reported according to defined accounting standards. *Based on verifiable past data subject to audit.*
- Long-Run Marginal Cost (LRMC)- the levelized incremental investment and operating cost of serving an additional kWh of energy demand (or kW of peak) for an indefinite period of time. *Based on future projections.*

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Similar Terms

- Embedded Cost
- Accounting Cost
- Financial Cost
- Reported Cost

General Embedded Cost Procedure

- Define the boundaries of the enterprise activities to be regulated and period of study ("test year").
- Itemize out-of-pocket expenses (fuel/purchased power, labor)
- Estimate depreciation, "reasonable" allowance for profit and taxes
- Separate costs by function
- Classify costs as fixed, variable with sales, and variable with number of customers
- Differentiate costs by time period
- Allocate costs to tariff categories

Revenue Requirements

Time Period

- Pure embedded cost approach- past period, usually 12 months
- WEAKNESS- past does not predict future
- RESPONSE- adjustment of test year data or project for future year of group of years (forward-looking)

Forward-looking derivatives supplement embedded cost data with projections.

Accounting Data

- Pure embedded cost approach- completely supported by accounting data
- In the short term, adjustments often have to be made to reflect
  - » direct subsidies
  - » undervalued assets
  - » allocations between activities using common resources (combined heat and power)
  - » unaccounted costs

Uniform System of Accounts

100 Series	Assets and other debits
200 Series	Liabilities and other credits
300 Series	Electric plant accounts
400 Series	Income and revenue accounts
500 Series	Electric operation & maintenance expenses
900 Series	Customer accounts, customer service and informational sales, and general and administrative expenses

Is profit a cost?

Giving the opportunity for a fair return to investors is one of the fundamental reason for economic regulation.

If it is not done, private investment will not be made.

If the government makes the investment without a return, it represents an indirect subsidy.

It is a cost.

Revenue Requirements Calculation

Total revenue requirements (including VAT) = Operating expenses + Allowable after-tax profit + Income taxes + VAT - Unregulated revenue

Revenue Requirements Example

		Label	Description
Rate Base	147,877	A	
Allowable Rate of Return	5%	B	
Income Tax Rate	42%	C	
VAT Rate	10%	D	
Operating Expenses			
Fuel	8,293,609		
Purchases	249,578		
Material & Others	942,214		
Labor & Services	550,613		
Depreciation	1,057,029		
Other	44,360		
Total Expenses	11,137,402	E	
Operating Income	854,114	F	E-G
Income Taxes	358,728	G	H*[1/(1-C)]
Return (Net Income)	495,386	H	A*B
Other Revenue	340,581	I	
VAT	1,294,548	J	[D/(1-D)]* (E+G+H-I)
Total Revenue Requirements	12,945,484	K	E+G+H+-I+J

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Rate Base

Investment basis upon which enterprise is allowed to earn a "reasonable" return

Rate base = Fixed assets in service - Accumulated depreciation + Working capital

Return (net income) = Rate base x Allowable after-tax rate of return

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Fair Rate of Return

- Weighted average of debt and equity
- Numerous methods for estimating return on equity
  - » discounted cash flow
  - » comparable earnings
  - » risk premium
  - » capital asset pricing model
- Other factors
  - » Is rate base made up of historical or revalued costs?
  - » Are tariffs to be inflation-adjusted?

Functionalization and Classification

Functionalization

Functionalization- process of assigning revenue requirements to enterprise functions

» Production

» Transmission

» Distribution

» Customer Service

Usually corresponds to accounting system

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Classification

Refinement of functionalization.

Assignment of functionalized costs to cost categories

» Energy

» Demand

» Customer

May require conventional rules and analyst judgment in additional to accounting cost categories.

Typical Functions and Classes

Functions	Classes		
	Energy	Demand	Customer
Production			
Thermal	x	x	
Hydro	x	x	
Other	x	x	
Transmission	x	x	x
Distribution			
Lines	x	x	x
Substations	x	x	x
Services			x
Meters			x
Customer Services			x

Framework for Estimating Revenue Requirement for the Transmission Function

General Approach for Transmission Services

- Define services in terms of their attributes
- Identify specific service costs
- Calculate costs, using one of several methods selected to meet particular objectives

Approach can be used with embedded and marginal cost estimation methods

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Transmission Service Attributes

- Amount (MW or MWh)
- Firmness
- Duration
- Receipt and delivery points
- Time/use profile
- Loss responsibility
- Other characteristics

Types of Transmission Service

- Point-to-point service
  - » Firm
    - – Short-term
    - – Long-term
  - » Non-firm
- Network service
  - » Firm
    - – Short-term
    - – Long-term
  - » Non-firm

Transmission Cost Components

- Analyze and arrange for requested service
- Bill for service and collect revenue
- Provide for reserve transmission capacity
- Provide additional facilities, if necessary
- Control power flow and frequency
- Provide adequate reactive supply and voltage control
- Keep system secure and available
- Monitor/meter service delivery

Transmission Service Costs

Costs may be incurred by generation, transmission, distribution or customer service

Example- A particular service may require increased reactive power from generation facilities. Investment and operation to provide the reactive power is made at generation facilities, but is part of a transmission service.

Transmission Cost Calculation Methods

- Traditional Methods in US
  - » Cost accounting and analysis
  - » Simple incremental and average cost
  - » Contract path
- Emerging Methods
  - » Megawatt-mile
  - » Rated system path
  - » Transmission cost actual path
  - » Impacted megawatt-mile
  - » General agreement on parallel paths
  - » Allocated contract path
  - » Investment cost related
  - » Nodal long-run marginal cost with expansion
  - » Nodal short-run marginal cost

MW-Mile Methodology

- Compute MW-mile rating of transmission system
- Determine cost/MW-mile
- Simulate power flow with and without transmission service being studied
- Projected changes in line loadings used to developed in incremental change in MW-miles of loading
- Transmission service bill = incremental change x cost/MW-mile

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Functionalization, Classification and Allocation of Transmission Costs

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General Approaches

- Rolled-in Transmission Plant Method

Based on philosophy that transmission system is integrated and used by all customers.

- Subfunctionalized Transmission Plant Method

Subsystems distinguished based on use, line configuration, geography or voltage level

Example Transmission Subfunctions

- Backbone and Inter-tie Facilities
- Generation Step-up Facilities
- Subtransmission Plant
- Radial Facilities
- Plant Reclassification (e.g., distribution level system serving as transmission for cogenerator, capacitor banks and synchronous condensers located within distribution system)

Transmission Cost Allocation Methods

Customer Group Transmission Cost = Demand Allocation Factor x System Transmission Cost

- Single System Coincident Peak
- Average Seasonal System Coincident Peak
- Monthly Average System Coincident Peak
- Single Non-Coincident Peak
- Month Average Non-coincident Peak
- Average and Excess Allocation

Transmission Cost Allocation-Example

Month	System			Customer Group		
	Sales (GWh)	Coincident Peak Demand (MW)	Non-coincident Peak Demand (MW)	Contribution to Coincident Peak Demand (MW)	Contribution to Non-coincident Peak Demand (MW)	Sales (GWh)
	A	B	C	D	E	F
1	55000	10000	10526	500	490	3066
2	49500	9000	9474	495	485	3035
3	44000	8000	8421	490	480	3005
4	38500	7000	7368	485	475	2974
5	33000	6000	6316	480	470	2943
6	27500	5000	5263	475	465	2913
7	27500	5000	5263	480	470	2943
8	27500	5000	5263	485	475	2974
9	33000	6000	6316	490	480	3005
10	38500	7000	7368	495	485	3035
11	44000	8000	8421	500	490	3066
12	49500	9000	9474	505	495	3097
Total (13)	467500	85000	89474	5880	5760	36056

Transmission Cost Allocation-Example (continued)

Single System Coincident Peak Demand Allocation Method

Principle: The annual system peak drives investment requirements

Allocation Formula: customer group contribution to system peak in month of highest demand/ maximum monthly peak load

= E1/C1 in table

Value in example = 500/10000

= 0.050

Monthly Average Non-coincident Peak Demand Allocation Method

Principle: Facilities are sized to meet maximum demands and installed to provide reliable service all year.

Allocation Formula: sum of monthly customer group contribution to non-coincident peak demand for 12 months/ sum of monthly system non-coincident peak demand for 12 months

= E13/C13 in table

Value in example = 5670/89474

= 0.064

Classification and Allocation of Distribution Costs

Distribution Subfunction Costs that are both Demand and Customer Related

- Poles, towers, and fixtures
- Overhead conductors and devices
- Underground conduit
- Underground conductors and devices
- Line transformers

Methods for Classifying Demand and Customer Costs

- Minimum-Size Method
  - » Determine minimum size equipment in each plant account
  - » Determine average unit cost
  - » Customer-related costs = minimum size equipment x average cost for each plant account
- Minimum-Intercept Method
  - » Relate installed cost to demand rating
  - » Customer-related costs = estimated cost at zero-loading

Allocation of Demand and Customer Costs

- Demand cost allocators
  - » Customer non-coincident demand and individual customer maximum demands are primary load characteristics
  - » Substation requirements affected by diversity
  - » Secondary feeder and line transformers allocated according to individual customer maximum demand
- Customer cost allocators
  - » number customers by tariff category
  - » Weighting factors reflecting differences in characteristics of customers between categories

Development of Load Data

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Need for Load Research

- Concept of cost responsibility requires knowledge of impact of tariff categories, particular services and individual transactions
- Particularly important in distribution cost allocation and time differentiation of costs
- It is not possible to obtain all information from direct metering

Data to be Obtained

For the test period

- Coincident system peak
- Tariff category non-coincident peak demand
- Customer non-coincident maximum demand
- Coincident factor (ratio of coincident demand of category to summed non-coincident demands)
- Diversity factor (reciprocal of coincident factor)
- Time-of-day sales by tariff category
- Load factor (system and tariff category)

Sampling

- Metering results of individual customers if large
- Sample smaller groups representing tariff categories
- Precision of sampling can be a regulatory issue (FERC requires relative precision of + or - 10% at a 90% confidence level
- Design of sample (statistical issues)

Data Collection

- Installation of meters, recorders and translators
- Duration of study
- Demographic data

Summary

Summary of Costing Issues

Approach	**Future Cost Consideration**	**Joint and Common Costs**	**Time Differentiation**
Embedded Cost	requires divergence from embedded cost	based on allocation	requires allocation
Marginal Cost	automatic	regression techniques for those that vary with production	automatic

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Summary of Strengths and Weaknesses of Embedded Cost Methods

- Strengths
  - » date verifiable and subject to audit
  - » simple, although tedious
  - » emphasis on financial data can encourage financial discipline
- Weaknesses
  - » past does not predict future
  - » significant adjustments required if inflation has eroded value of rate base
  - » incentive for adding to rate base, no incentive for performance

ENERGY RESTRUCTURING GROUP
IMPLEMENTING ENERGY REGULATION IN POLAND

PERFORMANCE BASED RATEMAKING

CENTRAL MAINE POWER CO. USA:
A CASE STUDY

Warsaw, 9-11 December 1996

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U.S.AID/Bechtel, World Bank/ESMAP

A CASE STUDY: *CENTRAL MAINE POWER COMPANY'S ALTERNATIVE RATE PLAN*

- WHAT IS AN ARP?
- WHY ADOPT AN ARP?
- STRUCTURE OF CMP'S ARP
- RESULTS UNDER THE ARP
- LESSONS LEARNED AND CHALLENGES FOR POLAND

WHAT IS AN ARP?

ARP (PERFORMANCE BASED RATES) MIDDLE OF SPECTRUM BETWEEN

- TRADITIONAL COST BASED RATES AND
- MARKET BASED RATES

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WHAT IS AN ARP?

Traditional Cost of Service

- Fixed Revenue Requirement
- Fixed Tariffs
- Highly Regulated
- No Flexibility
- Few Incentives
- Annual Changes
- Obligation to Serve

Market Based Rates

- Regulate Market, Not Prices
- No Price Regulation
- Great Flexibility
- Few Regulatory Checks
- Many Incentives
- Obligation to Serve?

WHAT IS AN ARP?

ARP

- Cost Based (Base Year)
- Multi-Year Cap
- Flexibility in Tariffs
- Earnings Bandwidth
- Targets and Incentives to Benefit Customers and Utility
- Periodic Reporting and Review
- Obligation to Serve
- Sharing of Risks, Rewards
- "Bandwidths", "Balance"

WHY ADOPT AN ARP?

- COMPETITIVE PRICING CAPABILITY
- PRICE STABILITY, PREDICTABILITY
- MINIMIZE FREQUENCY OF PRICE CHANGES
- INCREASE INCENTIVES FOR EFFICIENCY

WHY ADOPT AN ARP?

- REDUCE BURDENS OF REGULATORY PROCESS
- RECOGNIZE LIMITATIONS OF COST BASED PRICING
  - » Errors in Precise Calculations of Costs
  - » Hazards of Long-Term Forecasts

WHY ADOPT AN ARP?

- UTILITY BENEFITS
  - » Flexibility And Speed To Meet Markets
    - Attract New Load
    - Self-Generation Threat
    - IPP/CHP Threat
  - » Reduce Costs, Time of Rate Proceedings
    - Typical Rate Case is Annual
    - Cost for CMP - $1,000,000±

WHY ADOPT AN ARP?

- REGULATOR BENEFITS
  - » Incentives Placed On Utility
  - » Relieves Burdens of Annual Rate Cases
  - » But, Allows for Periodic Oversight
  - » Makes Utility, Not Regulator, Responsible Party
  - » Utility Is Party In Best Position to Influence Outcomes

WHY ADOPT AN ARP?

- CUSTOMER, PUBLIC BENEFITS
  - » Rate Stability
  - » Predictability
    - ∞ Important Especially for Industrial, Commercial Enterprises
- CUSTOMER, PUBLIC BENEFITS
  - » Lower Costs, Special Rates
  - » Reduces Time, Cost of Rate Proceedings

WHY ADOPT AN ARP?

- ARP COMBINES BEST OF BOTH WORLDS
  - » Regulatory Protections of Cost-Based Pricing
    - ℘ Ultimate Limits on Prices, Earnings
  - » Competitive Incentives of the Market
    - ℘ Flexibility, Lower Costs, Shared Benefits

CMP'S ARP: *THE TRANSITION TO PERFORMANCE-BASED REGULATION*

- RAISED IN 1993 RATE CASE
- NEGOTIATED DURING 1994
- RATES FROM 1993 AS STARTING POINT
- STIPULATION WITH ALL KEY PARTIES, FALL 1994
- ARP APPROVED BY MAINE PUBLIC UTILITIES COMMISSION EFFECTIVE JANUARY 1, 1995
- FIRST IN NATION

CMP'S ARP: *FEATURES OF THE ARP*

- REVENUE CAP
- FIVE-YEAR TERM (REVIEWS IN 1997, 1999)
- ANNUAL CAP ADJUSTMENT EACH JULY
- ADJUSTED CAP BASED ON INDEX
  - » Tied to Prior-Year GDP Inflation
  - » Offset for Productivity
  - » Provision for Certain Flow-Through Items
  - » Sharing of Earnings Gains, Shortfalls Outside Defined Bandwidth

CMP'S ARP: *FEATURES OF THE ARP*

- PRICING FLEXIBILITY
- DEMAND SIDE MANAGEMENT, SERVICE TARGETS WITH PENALTY PROVISIONS

CMP'S ARP: *ARP INDEX, FLOW-THROUGH*

- BASIS FOR CAP ADJUSTMENT: GDP INFLATION *LESS* OFFSETS FOR PRODUCTIVITY:
  - » 1995 Inflation - 0.5%
  - » 1996 Inflation - 1% (up to 3.5% net)
  - » 1997-99 0.625 x (Inflation - 1%)
- FLOW-THROUGH:
  - » DSM Costs
  - » 50% of *New* IPP Contract-Restructuring Savings

CMP'S ARP: *ARP MANDATES, SHARING*

- MANDATED COSTS
  - CMP *May* Ask For Recovery of Costs
    - Greater Than $3 Million Related to Governmental Requirements or Natural Disasters
    - Define "Requirements", "Disasters"?

CMP'S ARP: *ARP MANDATES, SHARING*

- SHARING MECHANISM

  » 50-50 Sharing If Earned ROE > 350 Basis Points Above Or Below Authorized Level

  » Authorized ROE Indexed to Capital Markets

CMP'S ARP: *PERFORMANCE*

- SERVICE TARGETS FOR:
  - » Service Reliability
  - » Customer Satisfaction
  - » On Time Installation
  - » Service Interruptions
  - » PUC Complaints
- DSM TARGET: AT LEAST 90% OF RESOURCE-PLAN LEVEL
- SLIDING SCALE OF FINANCIAL PENALTIES

CMP'S ARP: *REVIEW MECHANISMS*

- ANNUAL FILINGS, MARCH 15
  - » Index Calculations
  - » Speedy, Low Cost
- MID-PERIOD REVIEW, 1997
  - » Review Cost of Equity, Pricing Flexibility
  - » Could Modify or Terminate ARP
- FINAL REVIEW, 1999
  - » Decide Whether to Extend/Change ARP
  - » If ARP Ends, Select Successor Ratemaking Method

CMP'S ARP: *IMPORTANCE TO CMP*

- THREATS TO CUSTOMER BASE
  - » Loss of Wholesale and Related Industrial Customers
  - » Self Generation and Diesel Options
  - » Threats by Major Customers to Relocate
  - » Fuel Switching by Heating Customers
- ABILITY TO RETAIN AND GROW DESIRABLE LOAD
- BUT, CONCERNS ABOUT DISCRIMINATION AGAINST EXISTING CUSTOMERS

CMP'S ARP: *SPECIAL INCENTIVE RATES*

UNDER FORMER SYSTEM

- APPROVAL PROCESS UNCERTAIN, DELAYED
- "BUT FOR" TEST REQUIRED
- IMPACT ON OTHER CUSTOMERS UNCERTAIN AND CONTROVERSIAL
- EVEN RATES FOR *INCREMENTAL* USE QUESTIONED

CMP'S ARP: *RESPONDING TO THE MARKET*

THE NEW SYSTEM

- WHO QUALIFIES FOR MARKET-BASED PRICING?
  - » *Existing* Customer Classes
    - ฿ Reductions in Rate
  - » *New* Customer Classes
    - ฿ Pricing for Targeted Services or End Uses
  - » *Special-Contract* Customers
    - ฿ Guarantee Load

CMP'S ARP: *FLEXIBLE PRICES*

- CEILING: INDEXED PRICE-CAP LEVEL
- FLOOR: LONG-TERM MARGINAL COST

  (SHORT-TERM FLOOR MAY BE LOWER)
- RATE-COMPONENT RELATIONSHIPS CAN CHANGE

CMP'S ARP: *FLEXIBLE PRICES*

- TESTS FOR SOME PERMANENT LOAD PRICE REDUCTIONS
- EFFECTIVE DATES FOR PRICE REDUCTIONS:
  - » 30 Days If Tests Satisfied
  - » 120 Days If PUC Approval Required

CMP'S ARP: *BENEFITS TO LARGEST CUSTOMERS*

- MOST "AT RISK"
- 15% PRICE REDUCTION EFFECTIVE JANUARY 1, 1995
- HALF OF CLASS (17 CUSTOMERS) SIGNED FIVE-YEAR CONTRACTS
- SECURED 25% OF TOTAL LOAD

CMP'S ARP: *OTHER SPECIAL TARIFFS*

Snowmaking	11	2.0
Diesel Deferral	89	7.2
Space Heating	303	3.0
Economic Development	45	2.1
Separate Individual Customer Contracts	19	19.5

CMP'S ARP: *THE RESULTS*

- MANAGEMENT EMPHASIS HAS CHANGED
  - » Greater Emphasis On Cost Control
  - » Management of Fuel Cost Risk
  - » New Focus On Sales Targets
  - » New Kind of Revenue Uncertainty
    - Market Pricing vs. Regulated Pricing
  - » Employee Salary Incentives Based on ARP Targets

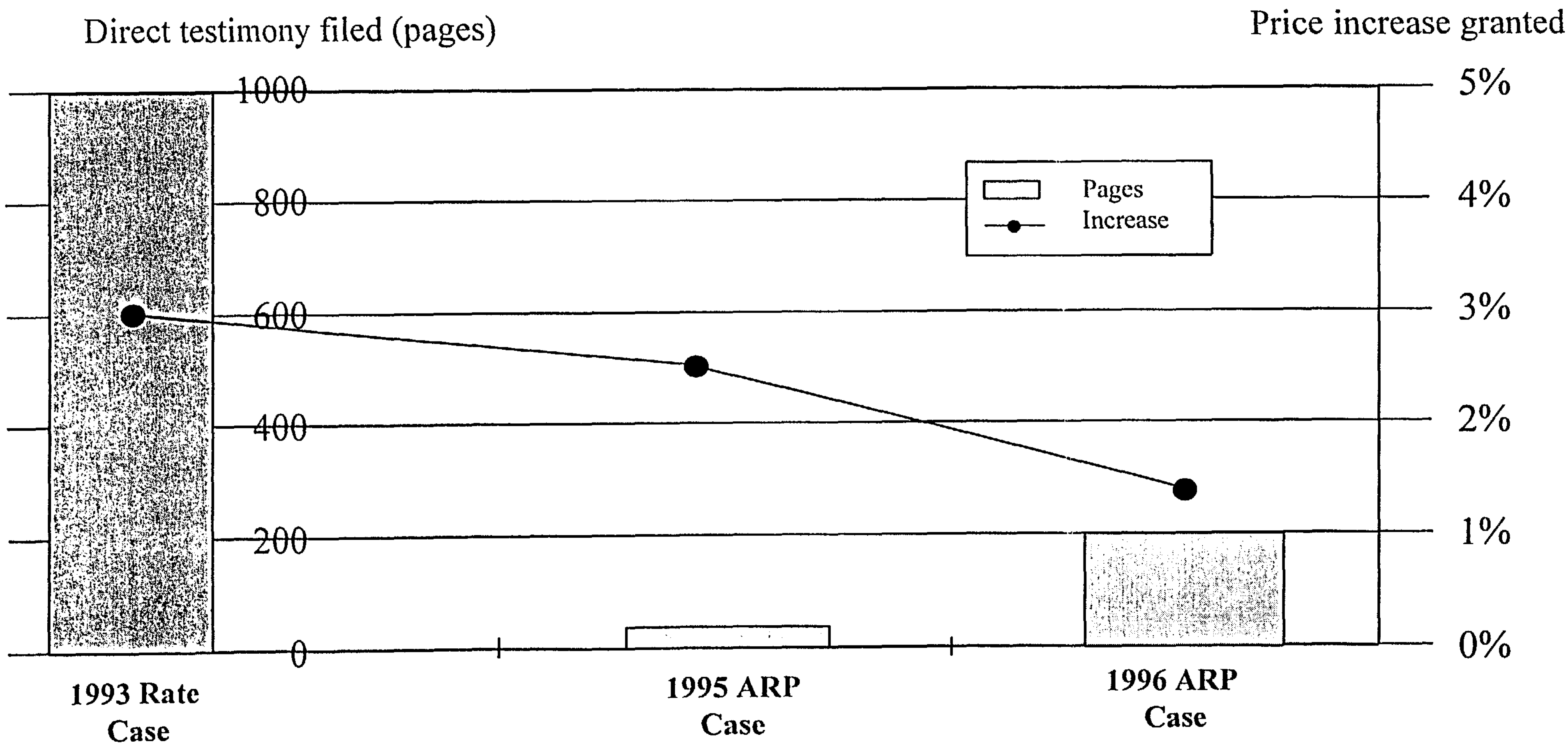
CMP'S ARP: *THE RESULTS*

ARP SERVICE MEASURES - 1995

Indicator	Target	Achieved
Employee knowledgeability	82%	86%
On-time installation	72%	74%
Service Interruption (minutes/ customer)	180	163
Interruptions/customer	2.00	1.73
PUC complaints/1,000 customers	1.17	0.95

CMP'S ARP: *THE RESULTS*

REGULATORY BURDEN EASED



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CMP'S ARP: *THE RESULTS*

- CUSTOMER-RELATIONS BENEFITS
  - » Price Stability Assured
  - » Favorable Publicity
  - » One Modest Increase a Year
  - » Measured Customer Satisfaction Up
- CUSTOMER SATISFACTION CRUCIAL
  - » In Transition to Competitive Environment

CMP'S ARP: *THE RESULTS*

- GAIN EXPERIENCE IN RISK, BENEFITS OF PERFORMANCE BASED RATES

- IMPROVE CUSTOMER SATISFACTION BEFORE OPEN COMPETITION

- DEVELOP NEEDED CUSTOMER FOCUS

CMP'S ARP: *CHALLENGE OF MAINE YANKEE*

- NUCLEAR UNIT OFF-LINE 11 MONTHS FOR REPAIRS
- MAJOR UNBUDGETED COSTS
  - » $10 million for CMP share of repairs
  - » $29 million for CMP replacement power
- REGULATORY PASS-THROUGH NO LONGER AVAILABLE

CMP'S ARP: *CHALLENGE OF MAINE YANKEE*

- OFFSET $16 MILLION BY COST CUTS, NEW REVENUES
- ROE SHARING FACTORED $3 MILLION INTO 1996 CAP CALCULATION
- COMPANY STILL BORE $20 MILLION UNDER ARP
  - » Customers Would Have Paid Under Traditional Method

CMP'S ARP: *THE BOTTOM LINE -- IT WORKED*

- PRICES STABILIZED
- PERCEPTION OF ENDLESS, LARGE INCREASES GONE
- MAJOR PORTION OF LOAD SECURED
- REGULATORY EXPENSES REDUCED
- MARKET-DRIVEN FOCUS SHARPENED
- KEY RESTRUCTURING STEPS IN PLACE

ARPs: *LESSONS AND CHALLENGES FOR POLAND*

- SETTING THE BASE LEVEL
  - » Difficult Where No History
  - » Challenge Where Current Prices Below Total Costs
  - » But Necessary Under Either Traditional Or Performance Based Rates

ARPs: *LESSONS AND CHALLENGES FOR POLAND*

- ARP BANDWIDTHS MINIMIZE IMPORTANCE OF

  » Determining Exact Levels of Costs

  » Setting Precise Rate of Return

ARPs: *LESSONS AND CHALLENGES FOR POLAND*

- WILL AN ARP ALLOW EASIER TRANSITION TO FULL, FAIR RATES?
- WHAT INCENTIVES TO TARGET
  - » Customer Service, Satisfaction
  - » ROE Bandwidths, Proper Index
- DURATION, REVIEW POINTS

ARPs: *LESSONS AND CHALLENGES FOR POLAND*

- ALLOWED PASS-THROUGHS
- IMPACT OF EFFICIENCY INCENTIVES ON LABOR ISSUES
  - » Utility Workers
  - » Miners
- FACTORING ENVIRONMENTAL COSTS
  - » Part of Cap?
  - » External, Allowable Pass-Throughs?

ARPs: *LESSONS AND CHALLENGES FOR POLAND*

- PUBLIC ACCEPTANCE?
  - » Strong Utility Earnings?
- ARP CONSISTENT WITH EUROPEAN UNION HARMONIZATION
  - » Unbundled Rates
  - » Greater Competition
- PROMOTES PRIVATE, FOREIGN INVESTMENT
- CAN BE IMPLEMENTED WITHOUT FULL DISAGGREGATION, PRIVATIZATION

POLAND AND ARPs: *FINAL THOUGHTS*

- EXCELLENT BRIDGING MECHANISM
  - » Traditional System to Market Based
  - » Fixed Prices to Competitive Pricing
  - » State Ownership to Private Ownership
  - » Poland to EU
- RETAINS REGULATORY REVIEW, ENFORCEMENT
- ENCOURAGES EFFICIENT UTILITY MANAGEMENT
- DESERVES SERIOUS CONSIDERATION

ADDITIONAL

MATERIALS

Trans for 12/96 ERA Trans

FINANCIAL STRUCTURE OF REGULATION

THE "TRADITIONAL" UNITED STATES-BASED MODEL

PURPOSES OF REGULATION

THE PURPOSE OF REGULATION IS TO ACT AS A SURROGATE FOR COMPETITIVE FORCES, AND TO ESTABLISH PRICES FOR REGULATED SERVICE AT A LEVEL WHICH WOULD EXIST UNDER COMPETITIVE CIRCUMSTANCES.

REGULATION OF UTILITIES IS GENERALLY CONCERNED WITH RATES, SERVICE, SAFETY, AND EFFICIENCY OF MANAGEMENT, BUT THE MAJORITY OF REGULATORY TIME IS OCCUPIED WITH RATE REGULATION.

RATE REGULATION HAS TWO ASPECTS:

1. CONTROL OF THE RATE LEVEL (EARNINGS)
2. CONTROL OF THE RATE STRUCTURE (PRICES)

IN A COMPETITIVE ENVIRONMENT, PRICES COVER:

- ALL PRUDENTLY INCURRED EXPENSES
- A FAIR AND REASONABLE RETURN ON CAPITAL INVESTED IN ASSETS USED TO PROVIDE GOODS OR SERVICES

ANY PRICE SETTING MECHANISM, INCLUDING REGULATION, WHICH FAILS TO IMPUTE COMPETITIVE INFLUENCES RESULTS IN PRICES WHICH ARE ECONOMICALLY INEFFICIENT, THEREBY RESULTING IN THE MISALLOCATION OF RESOURCES.

GOOD QUALITY REGULATION RECOGNIZES AND REWARDS EFFICIENCY (DOING THINGS WELL) AND EFFECTIVENESS (DOING THE RIGHT THINGS).

ROLE OF THE REGULATORS

REGULATORS MUST RECOGNIZE THAT, IN DISPATCHING THEIR OFFICIAL DUTIES, THEIR RESPONSIBILITY IS TO ENGENDER END RESULTS WHICH WOULD OTHERWISE RESULT FROM A COMPETITIVE ENVIRONMENT.

IT IS NOT THE RESPONSIBILITY OF REGULATORS TO DIRECT, INFLUENCE, OR PASS JUDGMENT UPON THE UTILITY'S MANAGEMENT POLICY OR PHILOSOPHY EXCEPT TO THE EXTENT THAT SUCH POLICY OR PHILOSOPHY IS ANTI-COMPETITIVE OR AN ABUSE OF MONOPOLY POSITION.

THE MOST CRITICAL ISSUES IN EFFECTIVE UTILITY REGULATION ARE:

- APPROPRIATE RESOLUTION OF RATEMAKING ISSUES WHICH MUST BE QUALITATIVELY RESOLVED BEFORE BEING QUANTITATIVELY RESOLVED.

- APPLICATION OF RATEMAKING PRINCIPLES WHICH ARE APPROPRIATE TO THE CIRCUMSTANCES.

- IMPLEMENTATION OF RATES WHICH ARE INTENDED TO PROVIDE FOR THE GREATEST ECONOMIC WELFARE OF THE UTILITY CONSTITUENCY.

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UNDERSTANDING REGULATORY TERMINOLOGY

REVENUE REQUIREMENT (TOTAL COST OF SERVICE) - THAT LEVEL OF AGGREGATE REVENUES ~~WHICH WILL~~ SUFFICIENT TO COVER ALL ALLOWABLE (PRUDENT) OPERATING EXPENSES AND PROVIDE A FAIR AND REASONABLE RETURN ON CAPITAL DEVOTED TO UTILITY SERVICE, USUALLY FOR A PERIOD OF ONE (OR SOMETIMES MORE THAN ONE) YEAR DURING WHICH RATES DESIGNED TO RECOVER THE REVENUE REQUIREMENT WILL BE IN EFFECT

REVENUE DEFICIENCY (OR EXCESS) - THE DIFFERENCE BETWEEN THE REVENUES OBTAINED UNDER EXISTING RATES AND THE REVENUE REQUIREMENT.

TARIFF - A DECLARATION OF ALL TERMS AND CONDITIONS OF PROVIDING A UTILITY SERVICE, INCLUDING THE RATES AT WHICH SERVICE WILL BE PROVIDED AND THE CONDITIONS OF ELIGIBILITY FOR EACH DIFFERENT RATE (OR CUSTOMER) CLASSIFICATION

RATE - THE PRICE, OR SCHEDULE OF PRICES, AT WHICH UTILITY SERVICE IS PROVIDED TO ITS CUSTOMERS. A UTILITY RATE NORMALLY HAS TWO COMPONENTS: CAPACITY (THE ABILITY TO SERVE THE CUSTOMER'S MAXIMUM LOAD) AND ENERGY USAGE (THE ACTUAL NUMBER OF UNITS OF UTILITY SERVICE PROVIDED). SIMPLIFIED RATES MAY INCORPORATE CAPACITY INTO THE USAGE RATE BASED ON AN ASSUMED RELATIONSHIP BETWEEN CAPACITY AND USAGE. SOME RATES HAVE A CUSTOMER CHARGE COMPONENT THAT RECOVERS BASIC CUSTOMER-RELATED COSTS THAT ARE INDEPENDENT OF USAGE. SOME RATES VARY BY SEASONS, TIME OF

RATE BASE - THE SCHEDULE OF THE ECONOMIC VALUE OF ALL ASSETS DEVOTED TO UTILITY SERVICE, FOR USE IN DETERMINING THE RETURN ON THE CAPITAL WHICH FUNDED THE ASSETS. RATE BASE NORMALLY INCLUDES ONLY NET PLANT IN SERVICE AND WORKING CAPITAL, AND EXCLUDES THE VALUE OF ASSETS WHICH ARE UNDER CONSTRUCTION OR OTHERWISE NOT IN SERVICE FOR AN EXTENDED PERIOD.

WORKING CAPITAL - THE FUNDS ~~WHICH~~ THAT ARE ASSUMED TO BE NECESSARY TO REASONABLY CONDUCT THE ONGOING BUSINESS AFFAIRS OF THE UTILITY. MAJOR WORKING CAPITAL ITEMS INCLUDE ACCOUNTS RECEIVABLE AND FUEL SUPPLY, LESS ACCOUNTS PAYABLE.

CAPITAL - THE MONIES ~~WHICH~~ THAT ARE ACQUIRED FROM INVESTORS IN THE FORM OF EITHER DEBT OR OWNERSHIP IN ORDER TO FUND THE ASSETS ~~WHICH~~ THAT ARE NECESSARY TO PROVIDE UTILITY SERVICE.

CAPITAL STRUCTURE - THE PERCENTAGE OF DEBT AND THE PERCENTAGE OF OWNERSHIP (EQUITY) RELATED TO THE TOTAL CAPITAL OF THE UTILITY.

COST OF CAPITAL - THE WEIGHTED AVERAGE COST OF ACQUIRING CAPITAL, BASED ON THE CALCULATED COST OF DEBT, THE REGULATORY DETERMINATION OF A FAIR AND REASONABLE RETURN ON OWNERSHIP, AND THE APPLICATION OF THE CAPITAL STRUCTURE TO WEIGHT THE COST OF EACH CAPITAL COMPONENT. FOR EXAMPLE, IN A STRUCTURE THAT IS 60% DEBT (AT, SAY, 8%) AND 40% EQUITY OWNERSHIP (AT, SAY, 11%), THE WEIGHTED COST OF CAPITAL IS ((.60 X .08) + (.40 X .11)), OR 9.20%.

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REGULATION OF PRIMARY UTILITY SERVICE

IN A RATEMAKING PROCEEDING, THE REVENUE REQUIREMENT OF THE UTILITY IS TRADITIONALLY COMPRISED OF THE ALLOWABLE OPERATING EXPENSES OF THE UTILITY AND THE RATE OF RETURN ON THE UTILITY ASSETS DEVOTED TO SERVICE.

REVENUE REQUIREMENT = TOTAL COST OF SERVICE

THE TRADITIONAL COST OF SERVICE FORMULA IS AS FOLLOWS:

$$R = E + kB$$

WHERE R = REVENUE REQUIREMENT

E = EXPENSES

k = COST OF CAPITAL

B = RATE BASE

IN THIS FORMULA, THE COST OF CAPITAL (k) IS THE WEIGHTED SUM OF THE DEBT COST (kd) AND EQUITY COST (ke), WITH THE RATIOS OF DEBT (D) AND EQUITY (E), TO THE TOTAL CAPITAL (C) SERVING AS WEIGHTS. THUS:

$$k = (kd \times D/C) + (ke \times E/C)$$

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ALLOWABLE OPERATING EXPENSES

IN A COMPETITIVE ENVIRONMENT, THE MARKET PRICE OF A COMMODITY REFLECTS THE EXPENSES INCURRED BY THE PROVIDER WITH THE LOWEST COST IN THE PRODUCTION AND DELIVERY OF THE COMMODITY. SIMILARLY, GOOD QUALITY REGULATION EXERTS PRESSURE UPON THE REGULATED UTILITY TO PRODUCE UTILITY SERVICES AT THE LOWEST REASONABLE COST CONSISTENT WITH OBJECTIVES FOR QUALITY, AND RELIABILITY AND ADEQUACY OF SERVICE, AT PRESENT AND IN THE FUTURE.

IN A REGULATED ELECTRIC UTILITY, REASONABLE COSTS INCLUDE:

ELECTRIC SUPPLY EXPENSES - FUEL COSTS
- PURCHASED POWER EXPENSES
- NON-FUEL OPERATIONS
- REPAIRS AND REPLACEMENTS

ELECTRIC DELIVERY EXPENSES - TRANSMISSION O&M (OPERATION Y MAINTENANCE)
- DISTRIBUTION O&M

ADMINISTRATIVE AND GENERAL EXPENSES - INCLUDES EXECUTIVE MANAGEMENT, PLANNING, MARKETING, PURCHASING, HUMAN RESOURCE MANAGEMENT, TREASURY FUNCTIONS, GENERAL ACCOUNTING, CUSTOMER ACCOUNTING, MANAGEMENT OF SUPPORT FACILITIES, ETC.

TAXES - IMPOSED ON INCOME BY NATIONAL OR REGIONAL GOVERNMENTS
- IMPOSED BASED ON EMPLOYMENT OR VALUE OF PROPERTY

DEPRECIATION - THE RECOVERY OF CAPITAL INVESTMENT

THE CONCEPT OF DEPRECIATION

AS AN ECONOMIC CONCEPT, DEPRECIATION IS A MEASUREMENT OF THE DECLINE IN ECONOMIC VALUE OF AN ASSET OVER THE PASSAGE OF TIME.

AS A FINANCIAL CONCEPT, DEPRECIATION IS AN ACCOUNTING MECHANISM TO:

1. RECOVER THE INVESTMENT IN CAPITAL ASSETS WHICH ARE DEPLETED OVER A PERIOD OF TIME.
2. ALLOCATE THE INVESTMENT COSTS OF CAPITAL ASSETS OVER THE PERIOD OF BENEFIT PROVIDED BY THE SUBJECT ASSETS. THE ALLOCATION OF COST USUALLY REFLECTS THE EXPECTED ECONOMIC LIFE OF THE ASSET, BUT MAY BE BASED ON OTHER CRITERION, SUCH AS UNITS-OF-PRODUCTION.

AS AN EXAMPLE, ASSUME THE PURCHASE OF AN ASSET FOR 16000 ~~DM~~ PLZ. THE ASSET HAS AN EXPECTED ECONOMIC LIFE OF TEN YEARS, AND UPON THE SALE OF THE ASSET AFTER TEN YEARS, THE OWNER IS EXPECTED TO RECOVER 2000 PLZ ~~DM~~ IN SALVAGE VALUE.

THE DEPRECIABLE VALUE OF THE ASSET IS (16000 ~~DM~~ PLZ LESS 2000 ~~DM~~ PLZ), OR 14000 ~~DM~~ PLZ. THE ANNUAL DEPRECIATION IS 14000 ~~DM~~ PLZ / 10 YEARS, OR 1400 ~~DM~~ PLZ PER YEAR.

AFTER USING THE ASSET FOR FIVE YEARS, THE OWNER SELLS THE ASSET FOR 10000 ~~DM~~ PLZ. THE "NET BOOK VALUE" OF THE ASSET IS 16000 ~~DM~~ PLZ (THE PURCHASE PRICE) LESS THE ACCUMULATED DEPRECIATION (5 YEARS X 1400 PLZ ~~DM~~/YEAR) OF 7000 ~~DM~~ PLZ, FOR A NET BOOK VALUE OF 9000 ~~DM~~ PLZ. UPON THE SALE, THE OWNER REALIZES A NET GAIN OF 1000 ~~DM~~ PLZ.

DETERMINATION OF THE RATE BASE

THE RATE BASE IS THE NET BOOK VALUE OF UTILITY ASSETS WHICH ARE USED AND USEFUL. TRADITIONALLY, ASSETS UNDER CONSTRUCTION ARE NOT INCLUDED IN RATE BASE BECAUSE THEY ARE NOT PROVIDING SERVICE. ALSO, ASSETS WHICH ARE OBSOLETE OR UNAVAILABLE FOR SERVICE ARE NOT INCLUDED IN RATE BASE.

TRADITIONALLY, THE RATE BASE CONSISTS OF INVESTMENT IN FACILITIES WHICH PROVIDE GENERATION, TRANSMISSION, DISTRIBUTION, AND GENERAL SERVICES, SUCH AS OFFICE BUILDINGS, WAREHOUSES FOR PARTS AND MATERIALS, SERVICE VEHICLES, ETC. THE RATE BASE ALSO INCLUDES AN ALLOWANCE FOR WORKING CAPITAL (CURRENT ASSETS LESS CURRENT LIABILITIES), WHICH ARE THE FUNDS NEEDED TO OPERATE THE UTILITY ON A DAY TO DAY BASIS. SOMETIMES THE RATE BASE INCLUDES A PORTION OF THE COSTS OF ASSETS UNDER CONSTRUCTION, PARTICULARLY WHEN THE ASSET COST IS RELATIVELY LARGE (SUCH AS A LARGE NEW GENERATING STATION).
THE VALUE OF THE RATE BASE IS TRADITIONALLY DETERMINED BASED ON THE HISTORICAL COST OF THE ASSETS LESS THE ACCUMULATED ALLOWANCE FOR DEPRECIATION.

WHEN A UTILITY IS PRIVATIZED (SOLD BY A GOVERNMENTAL UNIT TO PRIVATE INVESTORS), THE VALUE OF THE RATE BASE IS GENERALLY REVISED TO REFLECT THE MARKET CONCEPT THAT ASSETS, INCLUDING THE ASSETS COMPRISING A RATE BASE, ARE WORTH THE DISCOUNTED VALUE OF ALL ESTIMATED FUTURE REVENUES ARISING IN RESPECT OF SUCH ASSETS.

DETERMINATION OF COST OF DEBT

DEBT IS A CONTRACTUAL OBLIGATION OF THE UTILITY. EACH DEBT INSTRUMENT IS EVIDENCED BY AN AGREEMENT BETWEEN THE UTILITY AND THE LENDER OR LENDERS WHICH DESCRIBES THE TERMS AND CONDITION UNDER WHICH THE UTILITY HAS BORROWED THE FUNDS. STANDARD TERMS AND CONDITIONS INCLUDE THE RATE OF INTEREST, MATURITY DATE OR DATES, SECURITY FOR REPAYMENT (COLLATERAL), BORROWING COVENANTS, AND SPECIAL TERMS.

THE COST OF DEBT (kd) IS DETERMINED AS THE WEIGHTED SUM OF THE EFFECTIVE DEBT COST FOR ALL OUTSTANDING LONG TERM DEBT (EXCLUDES DEBT WITH AN INITIAL DURATION OF LESS THAN ONE YEAR) WITH THE WEIGHTS ASSIGNED TO EACH INCREMENT OF DEBT BASED ON THE PRINCIPAL AMOUNT OF THE OUTSTANDING INCREMENT AS A PERCENTAGE OF THE PRINCIPAL AMOUNT OF THE TOTAL DEBT OUTSTANDING.

THE EFFECTIVE COST OF EACH INCREMENT OF OUTSTANDING DEBT IS DETERMINED BASED ON THE "YIELD TO MATURITY", WHICH IS COMPUTED BY AN INTERNAL RATE OF RETURN CALCULATION WHERE:

INITIAL PROCEEDS = PV OF FUTURE INTEREST PAYMENTS PLUS
PV OF FUTURE PRINCIPAL PAYMENTS

WHERE: PV (THE PRESENT VALUE) IS DETERMINED BY FINDING THE INTERNAL RATE OF RETURN WHICH RESULTS IN EQUIVALENCY.

IN THIS FORMULA, THE INITIAL PROCEEDS ARE DETERMINED BY THE FACE AMOUNT OF THE DEBT LESS ALL DISCOUNTS (OR PLUS PREMIUMS) UPON ISSUANCE LESS ALL EXPENSES OF ISSUANCE.

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THE CONCEPT OF EQUITY CAPITAL

THE OWNERSHIP OF A PRIVATE ENTERPRISE IS MANIFESTED BY OWNERSHIP OF SHARES OF STOCK IN ANY SUCH ENTERPRISE. OFTEN, PRIVATE ENTERPRISES WILL ISSUE SEVERAL DIFFERENT CLASSES OF STOCK, EACH OF WHICH CONTAINS CERTAIN DISTINGUISHING CHARACTERISTICS WHICH AFFECT THE RISK OF EACH CLASS OF STOCK OUTSTANDING.

LARGER ENTERPRISES ARE OFTEN MADE AVAILABLE FOR PUBLIC OWNERSHIP. UNDER PUBLIC OWNERSHIP, THE STOCK IN AN ENTERPRISE IS OWNED DIRECTLY OR INDIRECTLY BY PRIVATE INDIVIDUALS. UNDER INDIRECT OWNERSHIP, THE STOCK IS OWNED BY ENTITIES, SUCH AS BANKS, PENSION FUNDS, MUTUAL FUNDS, AND INSURANCE COMPANIES, WHICH INVEST ON BEHALF OF LARGE GROUPS OF INDIVIDUALS.

WHEN THE STOCK OF AN ENTERPRISE IS PUBLICLY OWNED, THERE IS USUALLY AN ESTABLISHED MARKET FOR THE PURCHASE OR SALE OF SHARES OF SUCH STOCK, MOST OFTEN VIA THE LISTING ON A PUBLIC EXCHANGE, SUCH AS THE NEW YORK STOCK EXCHANGE, THE LONDON EXCHANGE, OR THE PARIS BOURSE. THE MARKET VALUE OF A SHARE OF STOCK, AS WITH THE MARKET VALUE OF ANY OTHER ASSET, IS DETERMINED BY THE PERCEPTION OF INVESTORS.

EQUITY AS AN ECONOMIC CONCEPT

IN ECONOMIC TERMS, THE MARKET VALUE OF A SHARE OF STOCK IS EQUAL TO THE PRESENT VALUE OF THE EXPECTED FUTURE CASH FLOWS ARISING FROM THE SHARE OF STOCK, CALCULATED USING A DISCOUNT RATE WHICH REFLECTS THE RISKINESS OF THE FUTURE CASH FLOWS.

EQUITY AS A FINANCIAL CONCEPT

FOR PURPOSES OF FINANCIAL PRESENTATION, THE VALUE OF EQUITY, COMMONLY KNOWN AS "BOOK VALUE", IS SHOWN BASED ON THE HISTORICAL PRICE AT WHICH EACH SHARE OF STOCK WAS INITIALLY SOLD BY THE ENTERPRISE, ADJUSTED BY THE EARNINGS AND DISTRIBUTIONS IN RESPECT OF EACH SHARE OF STOCK.

RELATIONSHIP BETWEEN MARKET PRICE AND BOOK VALUE

AN INVESTOR WISHING TO PURCHASE A SHARE OF STOCK IS INDIFFERENT WHETHER HE PURCHASES THE SHARE FROM THE ENTERPRISE OR ANOTHER INVESTOR. ASSUMING GOOD QUALITY REGULATION WHICH REFLECTS COMPETITIVE PRESSURES, AN INVESTMENT IN UTILITY ASSETS WHICH IS FUNDED BY THE SALE OF STOCK WOULD BE EXPECTED TO PRODUCE FUTURE REVENUES HAVING A PRESENT VALUE EQUAL TO (OR SLIGHTLY GREATER THAN) THE MARKET VALUE OF THE STOCK WHICH FUNDS THE INVESTMENT IN UTILITY ASSETS.

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REGULATORY DETERMINATION OF THE COST OF EQUITY

TWO LANDMARK DECISIONS OF THE UNITED STATES SUPREME COURT DEFINE THE LEGAL PRINCIPLES UNDERLYING THE CONCEPT OF A FAIR AND REASONABLE RATE OF RETURN ON THE EQUITY INVESTMENT IN A REGULATED PUBLIC UTILITY. FROM THESE CASES, COMMONLY KNOWN AS "HOPE" AND "BLUEFIELD", TWO STANDARDS OF FAIRNESS AND REASONABLENESS OF THE REGULATED RATE OF RETURN HAVE EMERGED.

1. A STANDARD OF CAPITAL ATTRACTION -
   REGULATED RETURNS SHOULD BE ADEQUATE TO MAINTAIN THE UTILITY'S ABILITY TO ATTRACT FINANCING ON REASONABLE TERMS AND CONDITIONS, BUT INADEQUATE TO REALIZE MONOPOLY GAIN.

2. A STANDARD OF COMPARABLE EARNINGS -
   RECOGNIZING THE OPPORTUNITY COST OF FUNDS INVESTED IN A PUBLIC UTILITY, REGULATED RETURNS MUST APPROXIMATE THE OBSERVED MARKET RETURNS EARNED BY INVESTMENTS IN OTHER ENTERPRISES HAVING CORRESPONDING RISKS.

OPTIMIZATION OF CAPITAL STRUCTURE

A REGULATED UTILITY WHICH IS INFLUENCED BY GOOD QUALITY REGULATION TO ACT AS A COMPETITIVE ENTERPRISE WILL STRIVE TO FINANCE ITS ASSETS USING THE COMBINATION OF DEBT AND EQUITY CAPITAL WHICH RESULTS IN THE LOWEST AGGREGATE COST OF CAPITAL.

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EXAMPLE RATE CASE

SMALL DISTRIBUTION & LEVEL ELECTRIC

A UTILITY FILES A RATE INCREASE REQUEST WHICH REFLECTS THE FOLLOWING ESTIMATES OF EXPENSES AND RATE BASE FOR THE "TEST YEAR" ENDING JUNE 30, ~~1992~~. 2000

		THOUSANDS OF ~~DM~~ PLZ
EXPENSES		
~~FUEL EXPENSE~~	~~200,000~~	
PURCHASED POWER	340,000	
~~OTHER GENERATING EXPENSE~~	~~120,000~~	
TRANSMISSION EXPENSE	30~~50~~,000	
DISTRIBUTION EXPENSE	105,000	
ADMIN. & GENERAL EXPENSE	35,000	
DEPRECIATION	40,000	
TAXES, OTHER THAN INCOME TAXES	3~~2~~0,000	580,000

RATE BASE			
WORKING CAPITAL		20,000	
UTILITY PLANT IN SERVICE	800,000		
LESS: ACCUM. DEPREC.	250,000	550,000	
TOTAL RATE BASE		570,000	
TIMES: COST OF CAPITAL		x 10.866%	61,936
REVENUE REQUIREMENT			641,936
ESTIMATED REVENUE AT CURRENT RATES			595,000
REVENUE DEFICIENCY (RATE INCREASE)			46,936

WEIGHTED COST OF CAPITAL

	~~DM~~ PLZ	%		COST		
DEBT	385,000	55.00	x	9.12	=	5.016
EQUITY	315,000	45.00	x	13.00	=	5.850
	700,000	100.00				10.866%

WEIGHTED COST OF DEBT

	~~DM~~ PLZ	%		COST		
ISSUE #1	100,000	25.97	x	9.50	=	2.467
ISSUE #2	150,000	38.96	x	8.75	=	3.409
ISSUE #3	135,000	35.07	x	9.25	=	3.244
	385,000	100.00				9.120%

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THE REVENUE REQUEST AND SUPPORTING EVIDENCE

A RATE PROCEEDING IS USUALLY INITIATED BY THE FILING BY THE UTILITY OF A REQUEST FOR A CHANGE IN THE REVENUE REQUIREMENTS UPON WHICH RATES ON SERVICE ARE PREDICATED. THE REGULATORY COMMISSION MAY ALSO DIRECT THE UTILITY TO MAKE SUCH A FILING. IN CONJUNCTION WITH THE FILING, THE UTILITY SUBMITS SUPPORTING EVIDENCE IN THE FORM OF WRITTEN TESTIMONY OF UTILITY OFFICIALS AND TECHNICAL EXPERTS.

THE SUPPORTING EVIDENCE GENERALLY CONSISTS OF:

- A GENERAL PRESENTATION OF THE RATE FILING SUBMITTED BY THE PRIMARY SPOKESPERSON FOR THE COMPANY. THIS DOCUMENT IS USUALLY SIMPLIFIED IN ORDER TO SERVE AS PUBLIC INFORMATION CONCERNING THE RATE FILING.

- A FINANCIAL OVERVIEW OF THE RATE FILING SUBMITTED BY THE PRIMARY FINANCIAL WITNESS FOR THE UTILITY.

- DETAILED EVIDENCE SUPPORTING EACH COMPONENT OF THE RATE FILING, INCLUDING COST OF SERVICE BY JURISDICTION AND CLASS OF CUSTOMER, RATES AND REVENUES, TAXES AND ACCOUNTING, DEPRECIATION, WORKING CAPITAL, AND COST OF CAPITAL INCLUDING COST OF EQUITY.

CONSIDERATION OF THE EVIDENCE

UPON A RATE FILING BY THE UTILITY, REBUTTAL TESTIMONY AND SUPPORTING EVIDENCE MAY BE SUBMITTED BY "INTERVENORS", WHO INCLUDE INDIVIDUALS, GROUPS, BUSINESSES OR ANY OTHER ENTITIES WHICH WOULD BE AFFECTED, DIRECTLY OR INDIRECTLY, BY CHANGES IN THE UTILITY'S RATES OR MODE OF OPERATIONS. THE UTILITY IS AFFORDED THE OPPORTUNITY TO RESPOND TO THE TESTIMONY AND EVIDENCE OF THE INTERVENORS.

THE MEMBERS OF THE REGULATORY COMMISSION HAVE THE RESPONSIBILITY TO WEIGH ALL TESTIMONY AND SUPPORTING EVIDENCE FROM TWO PERSPECTIVES:

FIRST, TO CONSIDER THE EVIDENCE PRESENTED IN ORDER TO RESOLVE OUTSTANDING ISSUES.

SECOND, TO CONSIDER THE WEIGHT OF THE EVIDENCE WITH RESPECT TO THE APPROPRIATENESS OF PROPOSED COURSES OF ACTION, THE BIASES WHICH EXIST WITHIN THE ESTIMATES OF EXPENDITURES AND RATE BASE, AND THE DEGREE OF RELIANCE WHICH CAN BE PLACED UPON THE ESTIMATES PROVIDED BY THE UTILITY.

THE REVENUE DECISION AND ACCOMPANYING ~~DECISION~~ EXPLANATION

UPON CONSIDERATION OF THE EVIDENCE, THE MEMBERS OF THE REGULATORY COMMISSION BEAR THE RESPONSIBILITY TO FORMULATE A REGULATORY DECISION CONCERNING THE REVENUE REQUIREMENT OF THE UTILITY.

THE REVENUE REQUIREMENT DECISION SHOULD BE ACCOMPANIED BY AN EXPLANATION WHICH ADEQUATELY EXPLAINS THE REASONING OF THE COMMISSION IN REACHING ITS DECISION, INCLUDING EXPLANATIONS OF THE REGULATORY RESOLUTION OF OUTSTANDING ISSUES, AND EXPLANATIONS OF THE ACCEPTANCE, REJECTION OR REVISION OF TEST YEAR FINANCIAL DATA UPON WHICH THE REVENUE REQUIREMENT DECISION IS BASED.

THE REVENUE REQUIREMENT DECISION MUST REFLECT THE EVIDENCE PRESENTED IN THE COURSE OF THE REGULATORY PROCEEDING. THE UTILITY IS ENTITLED TO APPEAL A DECISION OF A REGULATORY COMMISSION TO A JUDICIAL BODY IF IT BELIEVES THAT THE DECISION IS ARBITRARY OR CAPRICIOUS. ANY DECISION WHICH FAILS TO REFLECT APPLICATION OF EVIDENCE PRESENTED BY ONE OF THE PARTIES TO THE RATE PROCEEDING IS LIKELY TO BE INVALIDATED BY THE JUDICIAL REVIEW.

THE DECISION OF A REGULATORY COMMISSION IN ANY RATE PROCEEDING WITH RESPECT TO ANY TOPIC OR ISSUE DOES NOT CONSTITUTE A JUDICIAL PRECEDENT. HOWEVER, THE FAILURE OF UTILITY REGULATORS TO APPLY COMMON SENSE IN ADOPTING COURSES OF ACTION DETERMINED BY PREVIOUS REGULATORS CAN INCREASE THE RISK OF OPERATING THE UTILITY, AND CAN SUBJECT THE UTILITY TO HIGHER CAPITAL COSTS.

Example of United States Utility Tariff Schedule for Electricity Service

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Example of United States "Sample Utility" Historical Cost of Service Study

Principal Outputs

ABC PUBLIC UTILITIES
FULLY-FUNCTIONALIZED COST OF SERVICE ANALYSIS
PART 1: CLASSIFICATION, FUNCTIONALIZATION AND REVENUE REQUIREMENTS ANALYSIS

SUMMARY OF FUNCTIONAL COST OF SERVICE

		Out	In	Alloc	SYSTEM TOTAL	PRODUCTION DEMAND-RELATED	POWER SUPPLY ENERGY-RELATED	TRANSM. POWER SUPPLY	LOCAL SUBTRANS-MISSION	DISTRIBUTION SUBSTATIONS
	MAJOR UTILITY RATE BASE ITEMS									
1	TOTAL UTILITY PLANT	TOTPLT			352,300,000	255,661,177	2,113,629	29,012,567	12,917,158	21,272,620
2	TOTAL PROV. FOR DEP.& AMORT.	DRTOT			84,600,000	51,779,767	528,407	9,027,108	3,935,473	6,337,334
3	TOTAL NET PLANT	NETPLT			267,700,000	203,881,411	1,585,222	19,985,459	8,981,685	14,935,285
4	TOTAL CWIP	CWIP			70,000,000	50,000,000	0	10,987,500	6,948,000	2,064,500
5	NET PLANT PLUS CWIP	NTPLCW			337,700,000	253,881,411	1,585,222	30,972,959	15,929,685	16,999,785
	PLUS:									
6	TOTAL WORKING CAPITAL	WORK			46,900,000	12,367,626	26,434,651	2,188,868	772,963	1,508,105
	LESS:									
7	TOTAL ACCUM. DEF.INC.TAXES	DEFTOT			47,100,000	26,057,136	528,407	6,252,764	2,598,505	4,014,411
8	TOTAL RATE BASE	RBTOT			337,500,000	240,191,901	27,491,466	26,909,063	14,104,143	14,493,480
	MAJOR ELEMENTS OF COST OF SERVICE									
9	TARGET RATE OF RETURN	TARGET			13.01	13.01	13.01	13.01	13.01	13.01
10	REQUIRED RETURN @ C.O.S.	RTNREQ			43,905,775	31,246,849	3,576,397	3,500,632	1,834,825	1,885,474
11	FEDERAL INC. TAX @ C.O.S.	NEWFIT			27,860,475	19,836,305	2,133,211	2,261,873	1,167,893	1,203,204
12	STATE INC. TAX @ C.O.S.	NEWSIT			2,908,750	2,069,181	242,435	234,438	123,530	122,366
13	TOTAL O & M EXPENSE	OMTOT			287,500,000	48,528,411	199,977,209	9,665,367	2,566,484	6,169,202
14	TOTAL DEPR. & AMORT. EXPENSE	DXTOT			10,200,000	7,353,643	63,409	880,162	362,832	548,394
15	OTHER TAXES @ C.O.S.	NWTXOT			13,425,000	7,907,030	2,250,465	1,013,980	414,754	694,195
	LESS:									
16	REVENUES OTHER THAN SALES	NSLREV			3,300,000	153,337	105,681	86,024	16,704	38,185
17	ALLOWANCE FOR FUNDS USED	AFUDC	ALLOW	CWIP	0	0	0	0	0	0
18	TOTAL REVENUE REQUIREMENT	REVREQ			382,500,000	116,788,081	208,137,444	17,470,427	6,453,6[illegible]4	10,584,650

ABC PUBLIC UTILITIES
FULLY-FUNCTIONALIZED COST OF SERVICE ANALYSIS
PART 1: CLASSIFICATION, FUNCTIONALIZATION AND REVENUE REQUIREMENTS ANALYSIS

SUMMARY OF FUNCTIONAL COST OF SERVICE

		Out	In	Alloc	DISTRIBUTION: PRIMARY LINES DEMAND	PRIMARY LINES CUSTOMER	LINE TRANSFORMERS DEMAND	LINE TRANSFORMERS CUSTOMER	SECONDARY LINES DEMAND	SECONDARY LINES CUSTOMER
	MAJOR UTILITY RATE BASE ITEMS									
1	TOTAL UTILITY PLANT	TOTPLT			5,422,466	2,840,824	6,112,384	3,249,515	3,140,738	1,798,542
2	TOTAL PROV. FOR DEP.& AMORT.	DRTOT			2,277,521	1,193,368	2,593,426	1,378,738	1,315,484	753,311
3	TOTAL NET PLANT	NETPLT			3,144,945	1,647,457	3,518,958	1,870,777	1,825,254	1,045,231
4	TOTAL CWIP	CWIP			0	0	0	0	0	0
5	NET PLANT PLUS CWIP	NTPLCW			3,144,945	1,647,457	3,518,958	1,870,777	1,825,254	1,045,231
	PLUS:									
6	TOTAL WORKING CAPITAL	WORK			576,043	309,241	487,677	259,263	378,72[illegible]	207,422
	LESS:									
7	TOTAL ACCUM. DEF.INC.TAXES	DEFTOT			1,330,261	696,917	1,498,796	796,802	770,59[illegible]	441,283
8	TOTAL RATE BASE	RBTOT			2,390,727	1,259,780	2,507,839	1,333,238	1,433,38[illegible]	811,370
	MAJOR ELEMENTS OF COST OF SERVICE									
9	TARGET RATE OF RETURN	TARGET			13.01	13.01	13.01	13.01	13.0[illegible]	13.01
10	REQUIRED RETURN @ C.O.S.	RTNREQ			311,013	163,886	326,248	173,443	186,470	105,552
11	FEDERAL INC. TAX @ C.O.S.	NEWFIT			210,899	111,042	222,452	118,262	126,01[illegible]	71,439
12	STATE INC. TAX @ C.O.S.	NEWSIT			19,424	10,239	20,132	10,703	11,69[illegible]	6,614
13	TOTAL O & M EXPENSE	OMTOT			3,140,143	1,704,458	2,204,799	1,172,133	2,185,26[illegible]	1,175,751
14	TOTAL DEPR. & AMORT. EXPENSE	DXTOT			172,012	90,119	194,162	103,222	99,59[illegible]	57,032
15	OTHER TAXES @ C.O.S.	NWTXOT			188,122	99,117	200,138	106,399	113,91[illegible]	64,447
	LESS:									
16	REVENUES OTHER THAN SALES	NSLREV			880,410	461,363	10,521	5,593	507,51[illegible]	290,626
17	ALLOWANCE FOR FUNDS USED	AFUDC	ALLOW	CWIP	0	0	0	0	0	0
18	TOTAL REVENUE REQUIREMENT	REVREQ			3,161,201	1,717,498	3,157,409	1,678,568	2,215,443	1,190,208

ABC PUBLIC UTILITIES
FULLY-FUNCTIONALIZED COST OF SERVICE ANALYSIS
PART 1: CLASSIFICATION, FUNCTIONALIZATION AND REVENUE REQUIREMENTS ANALYSIS

SUMMARY OF FUNCTIONAL COST OF SERVICE

BREAKDOWN OF FUNCTIONAL COST

		Out	In	Alloc	SYSTEM TOTAL	PRODUCTION POWER SUPPLY DEMAND-RELATED	PRODUCTION POWER SUPPLY ENERGY-RELATED	TRANSM. POWER SUPPLY	LOCAL SUBTRANS-MISSION	DISTRIBUTION SUBSTATIONS
1	REQUIRED RETURN @ C.O.S.	RTNREQ			43,905,775	31,246,849	3,576,397	3,500,632	1,834,82[illegible]	1,885,474
2	% OF OVERALL REV. REQMT.	RTNSHR			11.48	26.76	1.72	20.04	28.4[illegible]	17.81
3	FEDERAL INC. TAX @ C.O.S.	NEWFIT			27,860,475	19,836,305	2,133,211	2,261,873	1,167,89[illegible]	1,203,204
4	% OF OVERALL REV. REQMT.	FITSHR			7.28	16.98	1.02	12.95	18.1[illegible]	11.37
5	STATE INC. TAX @ C.O.S.	NEWSIT			2,908,750	2,069,181	242,435	234,438	123,53[illegible]	122,366
6	% OF OVERALL REV. REQMT.	SITSHR			0.76	1.77	0.12	1.34	1.9[illegible]	1.16
7	FUEL EXPENSE	FUELXP	FUEL	FENRGY	169,500,000	0	169,500,000	0	[illegible]	0
8	% OF OVERALL REV. REQMT.	FULSHR			44.31	0.00	81.44	0.00	0.0[illegible]	0.00
9	PURCHASED POWER EXPENSE	PURCH	PCHSES		43,000,000	22,200,000	20,800,000	0	[illegible]	0
10	% OF OVERALL REV. REQMT.	PCHSHR			11.24	19.01	9.99	0.00	0.0[illegible]	0.00
11	ALL OTHER O & M EXPENSE	OMOTHR			75,000,000	26,328,411	9,677,209	9,665,367	2,566,48[illegible]	6,169,202
12	% OF OVERALL REV. REQMT.	OOMSHR			19.61	22.54	4.65	55.32	39.7[illegible]	58.28
13	TOTAL O & M EXPENSE	OMTOT			287,500,000	48,528,411	199,977,209	9,665,367	2,566,48[illegible]	6,169,202
14	% OF OVERALL REV. REQMT.	ONMSHR			75.16	41.55	96.08	55.32	39.7[illegible]	58.28
15	TOTAL DEPR. & AMORT. EXPENSE	DXTOT			10,200,000	7,353,643	63,409	880,162	362,83[illegible]	548,394
16	% OF OVERALL REV. REQMT.	DXSHR			2.67	6.30	0.03	5.04	5.6[illegible]	5.18
17	OTHER TAXES @ C.O.S.	NWTXOT			13,425,000	7,907,030	2,250,465	1,013,980	414,75[illegible]	694,195
18	% OF OVERALL REV. REQMT.	OTHSHR			3.51	6.77	1.08	5.80	6.4[illegible]	6.56
19	REVENUES OTHER THAN SALES	NSLREV			3,300,000	153,337	105,681	86,024	16,70[illegible]	38,185
20	% OF OVERALL REV. REQMT.	NSLSHR			0.86	0.13	0.05	0.49	0.2[illegible]	0.36
21	TOTAL REVENUE REQUIREMENT	REVREQ			382,500,000	116,788,081	208,137,444	17,470,427	6,453,61[illegible]	10,584,650
22	% OF OVERALL REV. REQMT.	TOTSHR			100.00	100.00	100.00	100.00	100.[illegible]	100.00

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SUMMARY OF FUNCTIONAL COST OF SERVICE

		Out	In	Alloc	DISTRIBUTION: PRIMARY LINES DEMAND	DISTRIBUTION: PRIMARY LINES CUSTOMER	DISTRIBUTION: LINE TRANSFORMERS DEMAND	DISTRIBUTION: LINE TRANSFORMERS CUSTOMER	DISTRIBUTION: SECONDARY LINES DEMAND	DISTRIBUTION: SECONDARY LINES CUSTOMER
	BREAKDOWN OF FUNCTIONAL COST									
1	REQUIRED RETURN @ C.O.S.	RTNREQ			311,013	163,886	326,248	173,443	186,47[illegible]	105,552
2	% OF OVERALL REV. REQMT.	RTNSHR			9.84	9.54	10.33	10.33	8.4[illegible]	8.87
3	FEDERAL INC. TAX @ C.O.S.	NEWFIT			210,899	111,042	222,452	118,262	126,01[illegible]	71,439
4	% OF OVERALL REV. REQMT.	FITSHR			6.67	6.47	7.05	7.05	5.6[illegible]	6.00
5	STATE INC. TAX @ C.O.S.	NEWSIT			19,424	10,239	20,132	10,703	11,69[illegible]	6,614
6	% OF OVERALL REV. REQMT.	SITSHR			0.61	0.60	0.64	0.64	0.5[illegible]	0.56
7	FUEL EXPENSE	FUELXP	FUEL	FENRGY	0	0	0	0	[illegible]	0
8	% OF OVERALL REV. REQMT.	FULSHR			0.00	0.00	0.00	0.00	0.0[illegible]	0.00
9	PURCHASED POWER EXPENSE	PURCH	PCHSES		0	0	0	0	[illegible]	0
10	% OF OVERALL REV. REQMT.	PCHSHR			0.00	0.00	0.00	0.00	0.0[illegible]	0.00
11	ALL OTHER O & M EXPENSE	OMOTHR			3,140,143	1,704,458	2,204,799	1,172,133	2,185,26[illegible]	1,175,751
12	% OF OVERALL REV. REQMT.	OOMSHR			99.33	99.24	69.83	69.83	98.6[illegible]	98.79
13	TOTAL O & M EXPENSE	OMTOT			3,140,143	1,704,458	2,204,799	1,172,133	2,185,26[illegible]	1,175,751
14	% OF OVERALL REV. REQMT.	ONMSHR			99.33	99.24	69.83	69.83	98.6[illegible]	98.79
15	TOTAL DEPR. & AMORT. EXPENSE	DXTOT			172,012	90,119	194,162	103,222	99,59[illegible]	57,032
16	% OF OVERALL REV. REQMT.	DXSHR			5.44	5.25	6.15	6.15	4.5[illegible]	4.79
17	OTHER TAXES @ C.O.S.	NWTXOT			188,122	99,117	200,138	106,399	113,91[illegible]	64,447
18	% OF OVERALL REV. REQMT.	OTHSHR			5.95	5.77	6.34	6.34	5.1[illegible]	5.41
19	REVENUES OTHER THAN SALES	NSLREV			880,410	461,363	10,521	5,593	507,51[illegible]	290,626
20	% OF OVERALL REV. REQMT.	NSLSHR			27.85	26.86	0.33	0.33	22.[illegible]	24.42
21	TOTAL REVENUE REQUIREMENT	REVREQ			3,161,201	1,717,498	3,157,409	1,678,568	2,215,44[illegible]	1,190,208
22	% OF OVERALL REV. REQMT.	TOTSHR			100.00	100.00	100.00	100.00	100.00	100.00

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ABC PUBLIC UTILITIES
FULLY-FUNCTIONALIZED COST OF SERVICE ANALYSIS
PART 1: CLASSIFICATION, FUNCTIONALIZATION AND REVENUE REQUIREMENTS ANALYSIS

SUMMARY OF FUNCTIONAL COST OF SERVICE

		Out	In	Alloc	SYSTEM TOTAL	PRODUCTION DEMAND-RELATED	POWER SUPPLY ENERGY-RELATED	TRANSM. POWER SUPPLY	LOCAL SUBTRANS-MISSION	DISTRIBUTION SUBSTATIONS
	UNIT COSTS AT FUNCTIONAL LEVEL OF INCURRENCE									
1	TOTAL REVENUE REQUIREMENT	REVREQ			382,500,000	116,788,081	208,137,444	17,470,427	6,453,6[illegible]	10,584,650
2	UNITS USED IN ALLOCATION	FNUNIT	FNUNIT		23,573,199	1,000,023	5,255,797	982,555	980,20[illegible]	833,010
3	UNIT COST AT ALLOC. LEVEL	UNTCST			16.23	116.79	39.60	17.78	6.5[illegible]	12.71
	LOSS ADJUSTMENT FACTORS FOR DELIVERY AT:									
4	TRANSMISSION VOLTAGE	TRLOSS	TRLOSS		6.026840	1.017770	1.009070	1.000000	0.00000[illegible]	0.000000
5	SUBTRANSMISSION VOLTAGE	STLOSS	STLOSS		7.049751	1.028050	1.011600	1.010101	1.0000[illegible]	0.000000
6	PRIMARY VOLTAGE	PRLOSS	PRLOSS		10.116693	1.043660	1.022310	1.025438	1.0151[illegible]	1.010101
7	SECONDARY VOLTAGE	SCLOSS	SCLOSS		17.328319	1.076730	1.042510	1.057931	1.0473[illegible]	1.042111
	UNIT COSTS ADJUSTED TO:									
8	TRANSMISSION VOLTAGE	CSTTR			217,970.18	118.86	39.96	17.78	0.[illegible]	0.00
9	SUBTRANSMISSION VOLTAGE	CSTST			217,978.25	120.06	40.06	17.96	6.[illegible]	0.00
10	PRIMARY VOLTAGE	CSTPR			218,004.32	121.88	40.49	18.23	6.[illegible]	12.83
11	SECONDARY VOLTAGE	CSTSC			218,028.38	125.75	41.28	18.81	6.[illegible]	13.24

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SUMMARY OF FUNCTIONAL COST OF SERVICE

		Out	In	Alloc	DISTRIBUTION					
					....PRIMARY LINES.......		..LINE TRANSFORMERS.....		.....SECONDARY LINES....	
					DEMAND	CUSTOMER	DEMAND	CUSTOMER	DEMAND	CUSTOMER
	UNIT COSTS AT FUNCTIONAL LEVEL OF INCURRENCE									
1	TOTAL REVENUE REQUIREMENT	REVREQ			3,161,201	1,717,498	3,157,409	1,678,568	2,215,443	1,190,208
2	UNITS USED IN ALLOCATION	FNUNIT	FNUNIT		824,681	253,000	1,097,408	237,500	1,528,0[illegible]4	237,500
3	UNIT COST AT ALLOC. LEVEL	UNTCST			3.83	6.79	2.88	7.07	1.45	5.01
	LOSS ADJUSTMENT FACTORS FOR DELIVERY AT:									
4	TRANSMISSION VOLTAGE	TRLOSS	TRLOSS		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
5	SUBTRANSMISSION VOLTAGE	STLOSS	STLOSS		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
6	PRIMARY VOLTAGE	PRLOSS	PRLOSS		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
7	SECONDARY VOLTAGE	SCLOSS	SCLOSS		1.031687	1.000000	1.023958	1.000000	1.006040	1.000000
	UNIT COSTS ADJUSTED TO:									
8	TRANSMISSION VOLTAGE	CSTTR			0.00	0.00	0.00	0.00	0.00	0.00
9	SUBTRANSMISSION VOLTAGE	CSTST			0.00	0.00	0.00	0.00	0.00	0.00
10	PRIMARY VOLTAGE	CSTPR			3.83	6.79	0.00	0.00	0.00	0.00
11	SECONDARY VOLTAGE	CSTSC			3.95	6.79	2.95	7.07	1.46	5.01

ABC PUBLIC UTILITIES
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PART 2: ALLOCATION OF FUNCTIONALIZED COSTS AND CLASS REVENUE REQUIREMENTS ANALYSIS

SUMMARY OF RESULTS: RATE OF RETURN STUDY

		Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL INDUSTRIAL SERVICE	LIGHTING SERVICE
	RATE OF RETURN STATEMENT									
	UTILITY RATE BASE									
1	PLANT IN SERVICE	PLANT	TOTPLT		352,300,000	186,330,745	19,803,381	95,734,491	46,171,18[illegible]	4,260,198
2	ACCUM. PROV. FOR DEPR.	DEPR	TOTDEP		84,600,000	45,926,507	4,866,016	22,019,352	10,106,82[illegible]	1,681,298
3	NET PLANT IN SERVICE	NETPLT			267,700,000	140,404,238	14,937,365	73,715,140	36,064,35[illegible]	2,578,900
4	CONSTR. WORK IN PROGRESS	CONST	TOTCWP		70,000,000	35,868,175	3,860,033	20,319,820	9,753,03[illegible]	198,940
5	TOTAL NET PLANT	TOTNPT			337,700,000	176,272,413	18,797,398	94,034,959	45,817,38[illegible]	2,777,840
	PLUS:									
6	WORKING CAPITAL REQ'MTS.	WKCAP	TOTWCR		46,900,000	22,725,091	2,480,378	13,390,375	7,466,65[illegible]	837,505
	LESS:									
7	ACC. DEF. INCOME TAXES	ACCDIT	TOTADT		47,100,000	25,666,323	2,724,571	12,195,495	5,510,22[illegible]	1,003,385
8	UTILITY RATE BASE	RBASE	TOTRBT		337,500,000	173,331,182	18,553,206	95,229,839	47,773,81[illegible]	2,611,960
	UTILITY INCOME									
	REVENUES:									
9	SALES OF ELECTRICITY	SALES	REVREV		350,000,000	166,400,000	19,000,000	101,600,000	57,000,000	6,000,000
10	OTHER REVENUES	OTHREV			3,300,000	2,191,026	219,999	599,079	130,016	159,880
11	TOTAL OPERATING REVENUES	OPRREV	TOTREV		353,300,000	168,591,026	19,219,999	102,199,079	57,130,016	6,159,880
	EXPENSES:									
12	TOTAL O & M EXPENSES	ONMEXP	TOTONM		287,500,000	135,988,498	14,932,274	83,188,404	48,002,164	5,388,660
13		OTHTAX	TOTOTX		13,100,000	6,744,214	729,759	3,617,413	1,823,22[illegible]	185,393
14	STATE INCOME TAX	TOTSIT			1,300,000	596,240	103,672	401,204	183,480	15,404
15	FEDERAL INCOME TAX	TOTFIT			13,800,000	6,502,631	1,043,119	4,165,455	1,922,798	165,996
16	TOTAL OPERATING EXPENSES	TOTEXP			325,900,000	155,233,275	17,381,790	94,129,490	53,269,110	5,886,335
17	OPERATING INCOME	OPINC			27,400,000	13,357,751	1,838,209	8,069,589	3,860,906	273,545
18	ALLOWANCE FOR FUNDS USED	AFDC	TOTADC		0	0	0	0	0	0
19	TOTAL INCOME--RETURN	TOTINC			27,400,000	13,357,751	1,838,209	8,069,589	3,860,906	273,545
20	RATE OF RETURN--PERCENT	RORPCT			8.12	7.71	9.91	8.47	8.06	10.47
21	INDEX OF RETURN	RELROR			100	95	122	104	100	129

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SUMMARY OF RESULTS: RATE OF RETURN STUDY

		Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL-INDUSTRIAL SERVICE	LIGHTING SERVICE
	AT PRESENT RATES:									
1	TOTAL OPERATING REVENUES	OPRREV	TOTREV		353,300,000	168,591,026	19,219,999	102,199,079	57,130,01[illegible]	6,159,880
2	TOTAL OPERATING EXPENSES	TOTEXP			325,900,000	155,233,275	17,381,790	94,129,490	53,269,11[illegible]	5,886,335
3	TOTAL INCOME--RETURN	TOTINC			27,400,000	13,357,751	1,838,209	8,069,589	3,860,906	273,545
4	UTILITY RATE BASE	RBASE	TOTRBT		337,500,000	173,331,182	18,553,206	95,229,839	47,773,81[illegible]	2,611,960
5	RATE OF RETURN--PERCENT	RORPCT			8.12	7.71	9.91	8.47	8.0[illegible]	10.47
6	INDEX OF RETURN	RELROR			100	95	122	104	10[illegible]	129
	PROPOSED INCREASES:									
7	REVENUES	INCREV	INCRSE	REVINC	32,500,000	18,097,364	1,132,966	8,504,093	4,635,134	130,443
	EXPENSES:									
8	REVENUE TAXES	INCRTX			325,000	180,974	11,330	85,041	46,351	1,304
9	STATE INCOME TAX	INCSIT			1,608,750	895,820	56,082	420,953	229,43[illegible]	6,457
10	FEDERAL INCOME TAX	INCFIT			14,060,475	7,829,463	490,155	3,679,126	2,005,295	56,434
11	OPERATING EXPENSES	INCEXP			15,994,225	8,906,256	557,567	4,185,119	2,281,08[illegible]	64,195
	AT PROPOSED RATES:									
12	REVENUES	NEWREV			385,800,000	186,688,390	20,352,965	110,703,172	61,765,15[illegible]	6,290,323
13	OPERATING EXPENSES	NEWEXP			341,894,225	164,139,531	17,939,357	98,314,609	55,550,19[illegible]	5,950,530
14	UTILITY INCOME-RETURN	NEWINC			43,905,775	22,548,859	2,413,608	12,388,563	6,214,953	339,793
15	UTILITY RATE BASE	RBASE	TOTRBT		337,500,000	173,331,182	18,553,206	95,229,839	47,773,81[illegible]	2,611,960
16	RATE OF RETURN--PERCENT	NEWROR			13.01	13.01	13.01	13.01	13.01	13.01
17	INDEX OF RETURN	INDEX			100	100	100	100	10[illegible]	100

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SUMMARY OF RESULTS: REVENUE REQUIREMENTS AND BREAKDOWNS OF COSTS

		Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL INDUSTRIAL SERVICE	LIGHTING SERVICE
	REVENUE REQUIREMENTS BY FUNCTION									
1	PRODUCTION--DEMAND	PRDCOS	COSPRD	DPROD	116,788,081	59,104,154	6,249,070	33,545,554	17,889,304	0
2	--ENERGY	PRECOS	COSPRE	ENERGY	208,137,444	90,828,456	10,281,341	63,946,482	39,990,862	3,090,303
3	TOTAL PRODUCTION	PRTCOS			324,925,525	149,932,610	16,530,411	97,492,036	57,880,16[illegible]	3,090,303
4	POWER SUPPLY TRANSMISSION	TRNCOS	COSTRN	DTRANS	17,470,427	8,841,444	934,798	5,018,115	2,676,07[illegible]	0
5	SUBTRANSMISSION	SBTCOS	COSSBT	DSUBTR	6,453,614	3,448,032	411,215	2,075,406	381,870	137,091
6	TRANS. & SUBTRANS. TOTAL	TRTCOS			23,924,042	12,289,476	1,346,013	7,093,521	3,057,94[illegible]	137,091
7	DISTRIBUTION SUBSTATIONS	DSSCOS	COSDSS	DSUBS	10,584,650	6,621,108	789,633	2,910,655	0	263,253
8	PRIMARY LINES --DEMAND	PLDCOS	COSPLD	DPRIM	3,161,201	1,977,454	235,832	869,291	0	78,624
9	-CUSTOMER	PLCCOS	COSPLC	CPRIM	1,717,498	1,221,935	101,828	139,165	0	254,570
10	LINE TRANSF. --DEMAND	TXDCOS	COSTXD	DTRNSF	3,157,409	2,578,668	271,128	249,027	[illegible]	58,587
11	-CUSTOMER	TXCCOS	COSTXC	CTRNSF	1,678,568	1,272,178	88,346	53,007	[illegible]	265,037
12	SECY. LINES --DEMAND	SLDCOS	COSSLD	DSECY	2,215,443	1,823,254	198,369	164,823	[illegible]	28,997
13	-CUSTOMER	SLCCOS	COSSLC	CSECY	1,190,208	902,052	62,643	37,586	0	187,928
14	SERVICES --DEMAND	SVDCOS	COSSVD	DSVCES	234,007	195,136	21,231	17,640	0	0
15	-CUSTOMER	SVCCOS	COSSVC	CSVCES	86,112	77,501	5,382	3,229	[illegible]	0
16	TOTAL BULK DISTRIBUTION	DSTCOS			24,025,097	16,669,286	1,774,392	4,444,423	0	1,136,995
17	METERS	MTRCOS	COSMTR	CMTRS	1,449,662	1,087,315	104,201	251,291	6,85[illegible]	0
18	INST. ON CUST. PREM.--PLT.	INPCOS	COSINP	CINSTP	36,377	0	0	3,859	32,519	0
19	--EXP.	INXCOS	COSINX	CINSTX	217,787	128,784	5,366	8,872	74,76[illegible]	0
20	STREET LIGHTING	LGTCOS	COSLGT	CLGTNG	1,758,508	0	0	0	[illegible]	1,758,508
21	CUSTOMER ACCOUNTING	CACCOS	COSCAC	CUSTAC	4,661,448	3,747,891	312,324	589,797	11,42[illegible]	13
22	SALES & CUST. SVCE.	SLSCOS	COSSLS	CUSVCS	1,031,827	642,003	60,259	220,295	101,73[illegible]	7,532
23	SPECIFIC ASSIGNMENTS	SPCCOS	COSSPC	DSPEC	469,727	0	0	0	469,72[illegible]	0
24	SALES REVENUES	REVCOS	COSREV	RSALES	0	0	0	0	[illegible]	0
25	DEMAND	DMDCOS			160,534,560	84,589,250	9,111,277	44,850,511	21,416,97[illegible]	566,552
26	ENERGY	NRGCOS	PRECOS		208,137,444	90,828,456	10,281,341	63,946,482	39,990,86[illegible]	3,090,303
27	CUSTOMER	CUSCOS			13,827,996	9,079,658	740,348	1,307,100	227,30[illegible]	2,473,588
28	TOTAL REVENUE REQUIREMENTS	TOTCOS			382,500,000	184,497,364	20,132,966	110,104,093	61,635,13[illegible]	6,130,443
29	PRESENT RATE REVENUES	PRSREV	SALES		350,000,000	166,400,000	19,000,000	101,600,000	57,000,00[illegible]	6,000,000
30	REVENUE DEFICIENCY AT COS	REVDEF			32,500,000	18,097,364	1,132,966	8,504,093	4,635,13[illegible]	130,443
31	PERCENT REVENUE DEFICIENCY	PCTDEF			9.29	10.88	5.96	8.37	8.1[illegible]	2.17

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SUMMARY OF RESULTS: REVENUE REQUIREMENTS AND BREAKDOWNS OF COSTS

		Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL INDUSTRIAL SERVICE	LIGHTING SERVICE
	BREAKDOWN OF ALLOCATED CLASS COST									
1	REQUIRED RETURN @ C.O.S.	RTNREQ			43,000,000	22,044,485	2,382,033	12,151,554	6,085,77[illegible]	336,158
2	% OF OVERALL REV. REQMT.	RTNSHR			11.2	11.9	11.8	11.0	9.[illegible]	5.5
3	FEDERAL INC. TAX @ C.O.S.	NEWFIT			28,750,000	14,827,419	1,564,284	8,077,338	4,054,960	226,000
4	% OF OVERALL REV. REQMT.	FITSHR			7.5	8.0	7.8	7.3	6.[illegible]	3.7
5	STATE INC. TAX @ C.O.S.	NEWSIT			2,925,000	1,501,109	160,321	826,409	415,23[illegible]	21,926
6	% OF OVERALL REV. REQMT.	SITSHR			0.8	0.8	0.8	0.8	0.[illegible]	0.4
7	FUEL EXPENSE	FULEXP	TOTFUL		169,500,000	73,967,581	8,372,772	52,075,823	32,567,18[illegible]	2,516,637
8	% OF OVERALL REV. REQMT.	FULSHR			44.3	40.1	41.6	47.3	52.[illegible]	41.1
9	PURCHASED POWER EXPENSE	PCHEXP	TOTPCH		43,000,000	20,311,832	2,215,328	12,767,029	7,396,98[illegible]	308,826
10	% OF OVERALL REV. REQMT.	PCHSHR			11.2	11.0	11.0	11.6	12.[illegible]	5.0
11	ALL OTHER O & M EXPENSE	OMOTHR			75,000,000	41,709,085	4,344,174	18,345,552	8,037,99[illegible]	2,563,197
12	% OF OVERALL REV. REQMT.	OOMSHR			19.6	22.6	21.6	16.7	13.[illegible]	41.8
13	TOTAL O & M EXPENSES	ONMEXP	TOTONM		287,500,000	135,988,498	14,932,274	83,188,404	48,002,164	5,388,660
14	% OF OVERALL REV. REQMT.	ONMSHR			75.2	73.7	74.2	75.6	77.[illegible]	87.9
15	DEPR. & AMORT. EXPENSE	DEPEXP	TOTDXP		10,200,000	5,401,692	572,966	2,757,014	1,337,447	130,882
16	% OF OVERALL REV. REQMT.	DEPSHR			2.7	2.9	2.8	2.5	2.2	2.1
17	OTHER TAXES @ C.O.S.	NWTXOT			13,425,000	6,925,187	741,088	3,702,454	1,869,572	186,698
18	% OF OVERALL REV. REQMT.	OTHSHR			3.5	3.8	3.7	3.4	3.0	3.0
19	REVENUES OTHER THAN SALES	NSLREV			-3,300,000	-2,191,026	-219,999	-599,079	-130,016	-159,880
20	% OF OVERALL REV. REQMT.	NSLSHR			-0.9	-1.2	-1.1	-0.5	-0.2	-2.6
21	TOTAL REVENUE REQUIREMENT	REVREQ			382,500,000	184,497,364	20,132,966	110,104,093	61,635,134	6,130,443
22	% OF OVERALL REV. REQMT.	TOTSHR			100.0	100.0	100.0	100.0	100.0	100.0

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SUMMARY OF RESULTS: REVENUE REQUIREMENTS AND BREAKDOWNS OF COSTS

		Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL-INDUSTRIAL SERVICE	LIGHTING SERVICE
	CALCULATION OF UNIT COSTS									
	REVENUE REQUIREMENTS									
1	DEMAND	DMDCOS			160,534,560	84,589,250	9,111,277	44,850,511	21,416,97[illegible]	566,552
2	ENERGY	NRGCOS	PRECOS		208,137,444	90,828,456	10,281,341	63,946,482	39,990,86[illegible]	3,090,303
3	CUSTOMER	CUSCOS			13,827,996	9,079,658	740,348	1,307,100	227,30[illegible]	2,473,588
	BILLING UNITS									
4	DEMANDS-KW	DUNITS	DUNITS		26,180,000	15,000,000	2,040,000	6,400,000	2,500,00[illegible]	240,000
5	ENERGY USE AT METER-MWH	EUNITS	EUNITS		5,105,000	2,200,000	250,000	1,580,000	1,000,00[illegible]	75,000
6	NUMBER OF BILLS	CUNITS	CUNITS		2,655,739	2,160,000	180,000	312,000	3,72[illegible]	19
	UNIT COSTS									
7	DEMAND--$ PER KW*MONTH	DCOST			6.13	5.64	4.47	7.01	8.5[illegible]	2.36
8	ENERGY--MILLS PER KWH	ECOST			40.77	41.29	41.13	40.47	39.9[illegible]	41.20
9	CUSTOMER--$ PER MONTH	CCOST			5.21	4.20	4.11	4.19	61.1[illegible]	130,188.82

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PART 2: ALLOCATION OF FUNCTIONALIZED COSTS AND CLASS REVENUE REQUIREMENTS ANALYSIS

DEVELOPMENT OF ALLOCATED REVENUES, EXPENSES AND INCOME

		Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL INDUSTRIAL SERVICE	LIGHTING SERVICE
	OPERATIONS AND MAINTENANCE EXPENSE									
1	PRODUCTION--DEMAND	PRDONM	COSPRD	DPROD	48,528,411	24,559,276	2,596,647	13,939,029	7,433,460	0
2	--ENERGY	PREONM	COSPRE	ENERGY	199,977,209	87,267,436	9,878,251	61,439,397	38,422,980	2,969,145
3	TOTAL PRODUCTION	PRTONM			248,505,619	111,826,711	12,474,898	75,378,425	45,856,440	2,969,145
4	POWER SUPPLY TRANSMISSION	TRNONM	COSTRN	DTRANS	9,665,367	4,891,454	517,169	2,776,230	1,480,514	0
5	SUBTRANSMISSION	SBTONM	COSSBT	DSUBTR	2,566,484	1,371,219	163,533	825,351	151,863	54,519
6	TRANS. & SUBTRANS. TOTAL	TRTONM			12,231,851	6,262,674	680,702	3,601,581	1,632,376	54,519
7	DISTRIBUTION SUBSTATIONS	DSSONM	COSDSS	DSUBS	6,169,202	3,859,075	460,233	1,696,458	0	153,436
8	PRIMARY LINES --DEMAND	PLDONM	COSPLD	DPRIM	3,140,143	1,964,282	234,262	863,500	0	78,100
9	-CUSTOMER	PLCONM	COSPLC	CPRIM	1,704,458	1,212,658	101,055	138,108	0	252,637
10	LINE TRANSF. --DEMAND	TXDONM	COSTXD	DTRNSF	2,204,799	1,800,667	189,327	173,894	0	40,911
11	-CUSTOMER	TXCONM	COSTXC	CTRNSF	1,172,133	888,353	61,691	37,015	0	185,074
12	SECY. LINES --DEMAND	SLDONM	COSSLD	DSECY	2,185,267	1,798,419	195,667	162,578	0	28,602
13	-CUSTOMER	SLCONM	COSSLC	CSECY	1,175,751	891,095	61,882	37,129	0	185,645
14	SERVICES --DEMAND	SVDONM	COSSVD	DSVCES	5,817	4,850	528	438	0	0
15	-CUSTOMER	SVCONM	COSSVC	CSVCES	2,140	1,926	134	80	0	0
16	TOTAL BULK DISTRIBUTION	DSTONM			17,759,709	12,421,326	1,304,778	3,109,201	0	924,404
17	METERS	MTRONM	COSMTR	CMTRS	1,026,975	770,279	73,818	178,020	4,857	0
18	INST. ON CUST. PREM.--PLT.	INPONM	COSINP	CINSTP	904	0	0	96	808	0
19	--EXP.	INXONM	COSINX	CINSTX	204,438	120,890	5,037	8,328	70,183	0
20	STREET LIGHTING	LGTONM	COSLGT	CLGTNG	1,428,520	0	0	0	0	1,428,520
21	CUSTOMER ACCOUNTING	CACONM	COSCAC	CUSTAC	4,426,067	3,558,640	296,553	560,015	10,846	12
22	SALES & CUST. SVCE.	SLSONM	COSSLS	CUSVCS	1,652,167	1,027,978	96,487	352,738	162,904	12,061
23	SPECIFIC ASSIGNMENTS	SPCONM	COSSPC	DSPEC	263,750	0	0	0	263,750	0
24	SALES REVENUES	REVONM	COSREV	RSALES	0	0	0	0	0	0
25	DEMAND	DMDONM			74,729,239	40,249,242	4,357,366	20,437,478	9,329,586	355,567
26	ENERGY	NRGONM	PREONM		199,977,209	87,267,436	9,878,251	61,439,397	38,422,980	2,969,145
27	CUSTOMER	CUSONM			12,793,552	8,471,820	696,657	1,311,529	249,598	2,063,948
28	TOTAL OPER. & MAINT. EXP.	TOTONM			287,500,000	135,988,498	14,932,274	83,188,404	48,002,164	5,388,660

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ABC PUBLIC UTILITIES
FULLY-FUNCTIONALIZED COST OF SERVICE ANALYSIS
PART 2: ALLOCATION OF FUNCTIONALIZED COSTS AND CLASS REVENUE REQUIREMENTS ANALYSIS

SUMMARY OF ALLOCATION FACTORS

EXTERNAL ALLOCATION FACTORS

	Out	In	Alloc	SYSTEM TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	GENERAL SERVICE	COMMERCIAL INDUSTRIAL SERVICE	LIGHTING SERVICE
1 CP DEMAND AT PRODUCTION	DPROD	DPROD		1,000,023	506,092	53,509	287,241	153,18[illegible]	0
2 ANNUAL MWH AT PRODUCTION	ENERGY	ENERGY		5,255,797	2,293,561	259,620	1,614,749	1,009,83[illegible]	78,035
3 CP DEMAND AT TRANSMISSION	DTRANS	DTRANS		982,555	497,252	52,574	282,224	150,50[illegible]	0
4 CLASS NCP DEMAND @ SUBTR.	DSUBTR	DSUBTR		980,201	523,701	62,457	315,221	58,00[illegible]	20,822
5 CLASS NCP DEMAND @ DIST.	DSUBS	DSUBS		833,010	521,080	62,144	229,068	[illegible]	20,718
6 CLASS NCP DEMAND @ PRIMARY	DPRIM	DPRIM		824,681	515,870	61,523	226,777	[illegible]	20,511
7 CUSTOMERS AT PRIMARY & BELOW	CPRIM	CPRIM		253,000	180,000	15,000	20,500	[illegible]	37,500
8 AVG., CLASS & CUSTOMER NCP'S	DTRNSF	DTRNSF		1,097,048	895,963	94,204	86,525	[illegible]	20,356
9 CUSTOMERS AT SECONDARY	CTRNSF	CTRNSF		237,500	180,000	12,500	7,500	[illegible]	37,500
10 CUSTOMER NCP DEMANDS	DSECY	DSECY		1,528,054	1,257,550	136,821	113,683	[illegible]	20,000
11 CUSTOMERS AT SECONDARY	CSECY	CSECY		237,500	180,000	12,500	7,500	[illegible]	37,500
12 CUSTOMER NCP DEMANDS	DSVCES	DSVCES		1,499,000	1,250,000	136,000	113,000	[illegible]	0
13 CUSTOMERS AT SECONDARY	CSVCES	CSVCES		200,000	180,000	12,500	7,500	[illegible]	0
14 WEIGHTED CUSTOMERS	CMTRS	CMTRS		239,985	180,000	17,250	41,600	1,13[illegible]	0
15 PLANT INSTALLED BY CLASS	CINSTP	CINSTP		4,676,000	0	0	496,000	4,180,00[illegible]	0
16 DIRECT ASSIGNMENT OF EXPENSES	CINSTX	CINSTX		60,880	36,000	1,500	2,480	20,90[illegible]	0
17 DIRECT ASSIGNMENT	CLGTNG	CLGTNG		100	0	0	0	[illegible]	100
18 WEIGHTED CUSTOMERS	CUSTAC	CUSTAC		8,930,000	7,179,886	598,324	1,129,883	21,88[illegible]	25
19 DIRECT ASSIGNMENT	CUSVCS	CUSVCS		100	62	6	21	1[illegible]	1
20 DIRECT ASSIGNMENT	DSPEC	DSPEC		2,088,000	0	0	0	2,088,00[illegible]	0
21 SALES REVENUES	RSALES	RSALES		350,000	166,400	19,000	101,600	57,00[illegible]	6,000

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Example of Methodology for Alocation of a Rate Increase to Customer Classes, Based on a Cost of Service Study

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EXAMPLE OF THE "INDEX-OF-RETURN" STRATEGY FOR ALLOCATING RATE INCREASES
(Case 1: Using a Small Overall Percent Increase)

	TOTAL RETAIL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OUTDOOR LIGHTING
I. Class Revenues At Present Rates:					
Total Revenues	3,302,477.2	1,020,741.1	1,171,511.8	1,059,248.1	50,976.2
Base Rates Only	2,416,132.0	786,901.8	900,667.6	683,060.6	44,542.0
II. Results Of Class COS Allocations:					
Rate Base	8,296,507.0	3,214,886.0	2,572,932.0	2,419,023.0	89,666.0
Income	671,865.0	147,113.0	306,946.0	201,123.0	16,683.0
Rate Of Return	8.10%	4.58%	11.93%	8.31%	18.61%
Index Of Return	1.00	0.57	1.47	1.03	2.30
Gap Based On 1.0 Index	0.00	-0.43	0.47	0.03	1.30
III. Specification Of Index Strategy:					
Desired Reduction In Gap:	50%				
Change To Index	0.00	0.22	-0.24	-0.01	-0.65
Targeted Index	1.00	0.78	1.24	1.01	1.65
IV. Specification Of Overall Earnings:					
Targeted Rate Of Return	8.95%	7.00%	11.06%	9.06%	14.75%
Change In Rate Of Return	0.85%	2.42%	-0.87%	0.75%	-3.86%
Change In Income	70,265.0	77,923.4	(22,346.9)	18,147.3	(3,456.8)
Income Expansion Factor	1.64257				
Preliminary Incr.-$1,000	115,415.5	127,904.9	(36,706.5)	29,808.3	(5,681.3)
-Percent	3.495%	12.54%	-3.13%	2.81%	-11.14%
V. Specification Of Limits On Strategy--Bounds On Percentage Increases:					
Upper Limit Multiplier	2				
Lower Limit Multiplier	0				
Upper Limit On Pct Incr.	6.99%				
Lower Limit On Pct Incr.	0.00%				
Constrained Percent Increases		6.99%	0.00%	2.81%	0.00%
VI. Reallocation Of Revenue Mismatch Due To Limits:					
Preliminary Rev. Increase	101,154.3	71,340.0	0.0	29,808.3	0.0
Revenue Shortfall	14,261.1				
Increases Not Constrained	29,808.3	0.0	0.0	29,808.3	0.0
Allocated Shortfall	14,261.1	0.0	0.0	14,261.1	0.0
VII. Final Results:					
Total Increase--$1,000	115,415.5	71,346.0	0.0	44,069.4	0.0
--Percent	3.49%	6.99%	0.00%	4.16%	0.00%
Increase To Income	70,265.0	43,435.5	0.0	26,829.5	0.0
Income At New Rates	742,130.0	190,548.5	306,946.0	227,952.5	16,683.0
Rate Of Return At New Rates	8.95%	5.93%	11.93%	9.42%	18.61%
Index At New Rates	1.00	0.66	1.33	1.05	2.08
Improvement In Index	0.00	0.10	0.14	-0.03	0.22

COMMENTS

This worksheet relies on total revenues. However, base rate revenues could be used. That would only change the strategy and the regulatory parameters.

A policy choice: How fast to move toward cost--a smaller number means a slower rate of approach, while a value of 100% means "all at once."

Set by Revenue Requirements phase of case.

Result which would occur absent any limitations.

Additional recognition of non-cost factors:
- Billing Impact
- Equity and Fairness (E.g., should all share some?)

A smaller increase means a higher feasible cap.
A greater increase means a higher required floor.

Allocate where the constraints have not already limited the action. (Recheck to see if constraints are violated by the allocation.)

Example of United States Utility

Tariff Schedule for Electricity Service

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BEST AVAILABLE DOCUMENT

Date of Issue May 19, 1995 Date Effective June 5, 1995
Issued by Albert J. Budney, Jr., President, Syracuse, New York
Issued Under Authority of Order of the Public Service Commission
Dated May 12, 1995 in Case No. 94-E-0981.

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BOOK VALUATION:
HISTORIC-COST ACCOUNTING (HCA)

- based on the depreciated purchase cost of assets
- principal problem is that it does not allow for the impact of inflation, very important for companies with long-lived assets
- accounts can be revalued periodically, especially property

BOOK VALUATION:
CURRENT-COST ACCOUNTING (CCA)

- developed to overcome the problem of inflation

- several approaches:

  - revalued HCA
  - replacement cost
  - modern equivalent asset (MEA)
  - infrastructure renewal accounting

- consider each in detail

PROBLEMS WITH CCA

- subjective decision
- choice of approach can have large impact on value found
- ignored by the regulatory bodies in the UK when setting the rate base, although used by all as the basis of depreciation charges

MARKET VALUATION

- concerned with both sources of financee
- for quoted companies, market value of equity is easy to establish
- much harder to find the market value of debt
- two options exist

▪ current market value
▪ rebased initial market value

RATE-OF-RETURN REGULATION

- company institutes rate review

- regulator examines previous year's data

  - operating costs
  - capital employed
  - cost of capital

- regulator sets

  - price
  - price structure

- legalistic approach

AIMS OF RPI - X

- to mimic competitive pressure in a monopolistic industry

- to drive prices down
- to drive costs down

- to avoid the drawbacks of rate-of-return regulation

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THE BASIC RPI - X FORMULA

$$P_t \leq [(1+RPI_t - x)/100]p_{t-1}$$

$$\text{for } t=1,2,\ldots T$$

where:

P_t is current period price

P_{t-1} is last period price

RPI is current period inflation

x is real rate of price reduction

T is the review period

ALTERING THE REVIEW PERIOD

- the key difference between RPI - X and rate-of-return regulation lies in the length of the period review

$T = O \Rightarrow$ rate of return regulation
t = $\infty \Rightarrow$ pure “price-cap” regulation

SOME LESSONS FROM THE UK ON REGULATORY POLICIES TO INCREASE COMPETITION

- liberalisation is not sufficient when industry restructuring is limited
- proactive regulatory policies are required to stimulate competition
- policies that are asymmetric are more powerful that those that act symmetrically on incumbent and entrants(s)
- statutory duopolly did not simulate growth of effective competition
- market-share targets, crude and poor substitute for real competition
- asymmetric pricing policies/use of contracts can stimulate entry
- asymmetric publication of price lists can be helpful to entrants
- transparency of access terms and actual terms of access crucial in network industries

THE NATURE OF INCUMBENT ADVANTAGES IN UTILITY INDUSTRIES

- absolute advantages
  - access to inputs, network services, information

- first-mover advantages
  - sunk costs, contractual commitments, existing customer base

- strategic entry deterrence possibilities
  - predatory pricing, predatory use of network service and contracts

REGULATORY STRATEGIES TO INCREASE COMPETITION

- direct subsidies
- asymmetric obligations placed on incumbent relative to entrants
- restrictions on incumbent's pricing to favour entrant
- market-share targets placed on incumbent
- measures to reduce the cost of switching
- limitations on further entry
- favourable interconnection terms

INTERACTIONS OF COMPETITION AND REGULATION

- competition can enhance regulatory effectiveness via information revelation
- competition, by constraining monopoly behaviour, may reduce need for regulation
- competition may, owing to “cream=skimming” etc., limit possible price structures
- regulation may harm competition by lower prices
- regulation may limit predatory pricing or other strategic moves thereby enhancing competition
- regulation may provide favourable access terms to networks, thereby enhancing competition
- regulation and competition may be complements and not substitutes

CONCLUSIONS

- utility industries are vertically related, often including network services
- head-to-head competition may be feasible and/or desirable
- feasibility of competition may depend on industry restructuring
- competitions an imperfect incentive mechanism (as is monopoly regulation)
- competition may enhance regulation
- regulation may be a complement to competition (again dependent on industry restructuring)