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National Association of Regulatory Utility Commissioners Regulatory Partnership Program

The Energy Regulation Board of Zambia (ERB)
and
the Pennsylvania Public Utility Commission (PUC)
Third Activity

Cost of Service

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"The establishment of a rate for a regulated industry often includes two steps of different character, one of which may appropriately precede the other. The first is the adjustment of a general revenue level to the demands of a fair return. The second is the adjustment of a rate schedule conforming to that level, so as to eliminate discrimination and unfairness from its details."

Chief Justice Stone, Federal Power Commission vs. Natural Gas Pipeline Company - - 315 U.S. 575, 584 (1941).

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Criteria Of A Desirable Rate Structure

1. Simplicity, understandability, public acceptability, feasibility of application;
2. Freedom from controversies as to proper interpretation;
3. Effectiveness in yielding total revenue requirements under the fair return standard;
4. Revenue stability from year to year;
5. Stability of rates;
6. Fairness in specific rates in the apportionment of total costs;
7. Avoidance of undue discrimination;
8. Efficiency of rate classes and rate structure in discouraging wasteful use and promoting all justified use with respect to total amount and type of service.

Ratemaking Equation

- Revenues – Expenses = Net Income
- Net Income / Rate Base = Rate of Return
- (R-E)/Rate Base = Rate of Return
- Revenue Requirement = E+ROR(RB)

Developing Total Revenue Requirements

Rates charged for electric services must be sufficient to recover total costs in order to remain viable

Rate Base

- ✓Property considered to be used and useful
- ✓Based upon original cost or fair value
- ✓Must allow for depreciation

Rate Base Components

- Electric Plant in Service
- Accumulated Depreciation Reserves
- Accumulated Provision for Deferred Income Taxes
- Electric Plant Held for Future Use
- Construction Work in Progress
- Working Capital

Fair Rate of Return

- A utility is allowed the opportunity to earn a reasonable return on its investment
- A fair rate of return is one that will allow the utility to recover its costs of all classes of capital used to finance its rate base

Cost Accounting Is Allocation Of Responsibility For Revenue Requirement

Operation and Maintenance Expense

Fuel and Purchased Power Costs

Depreciation Expense

Return on Rate Base

Income Taxes

Property Taxes and Insurance

Administrative and General Expenses

Revenue Taxes

Working Capital Requirements

Cost of Service Study

- Once the revenue requirements are determined, then the proper allocation of the rate increase between the customer classes becomes an issue
- Many factors are considered in determining the revenue allocation and rate design
- Cost of service outweighs all the other factors
- Other factors include value of service, gradualism and social welfare considerations
- Apply all these factors with considerable judgement

Cost of Service

- Note – Cost of service is only a ratemaking guide or tool
- Other factors can be taken into consideration when designing rates and allocating revenues

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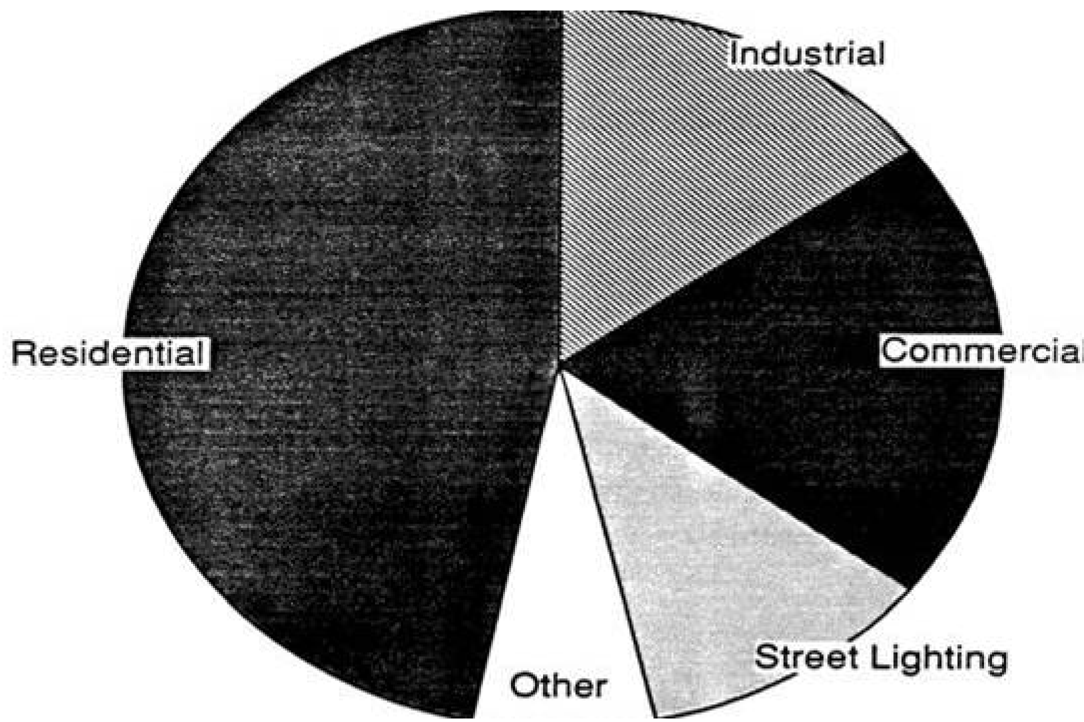

Determining Rate Classes

- How many classes are needed?
- How should customers be grouped?

Factors To Be Considered

- Homogeneous loads
- Size
- Location
- Diversity
- Value of service

Typical Customer Groups

Residential, Domestic

- Individual meter
- Master meter

Small Light and Power, Commercial

Medium Light and Power

Large Light and Power Customers

Agriculture and Pumping

Street Lighting

Cost of Service – Customer Demand

- Customer demand has major impact of the cost of service
- Affected by many factors including:

  Population density, price, weather, usage patterns, age and utilization of equipment

Cost of Service – Load Factor

- ✓ Cost of Service study attempts to identify the cost per unit to serve each particular customer class
- ✓ This concept is known as load factor
- ✓ Generally, residential and small commercial customers, who tend to consume utility service during peak periods, place a greater per unit cost on the system than large industrial customers, who operate around the clock at a stable level of demand

Load Factor

The ratio of the average load over a designated period of time to the peak load occurring during that period

Cost of Service – Load Factor

- A residential and small commercial customer will have a low load factor
- Large industrial customers generally have high load factors
- Load Factor determination is a science all to its self
- Demand Studies are performed to determine peak usage

Cost of Service - Pennsylvania PUC Requirements

- ✓ Increase in annual revenues in excess of $1 million must file a cost of service study with their rate filing
- ✓ Commission has also advocated that any utility with revenues exceeding $1 million file a cost of service study (water filings)
- ✓ Many small utilities with revenue approximating $100,000 will also file cost of service study

Cost of Service Study

- Fully allocated class cost of service study allocates each and every item of cost and assigns these costs to the various customer classes based upon engineering, operating, economic, and legal principles

Cost of Service Study – Three Basic Steps

- Functionalization
- Classification
- Allocation

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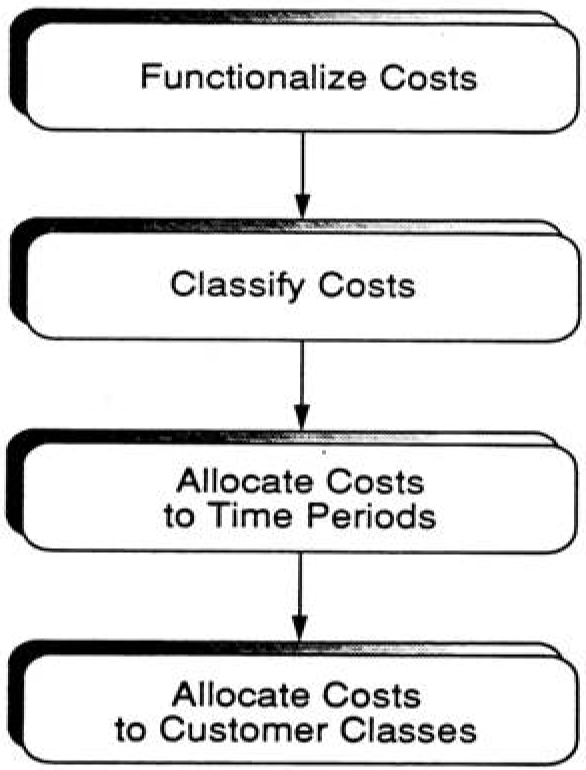
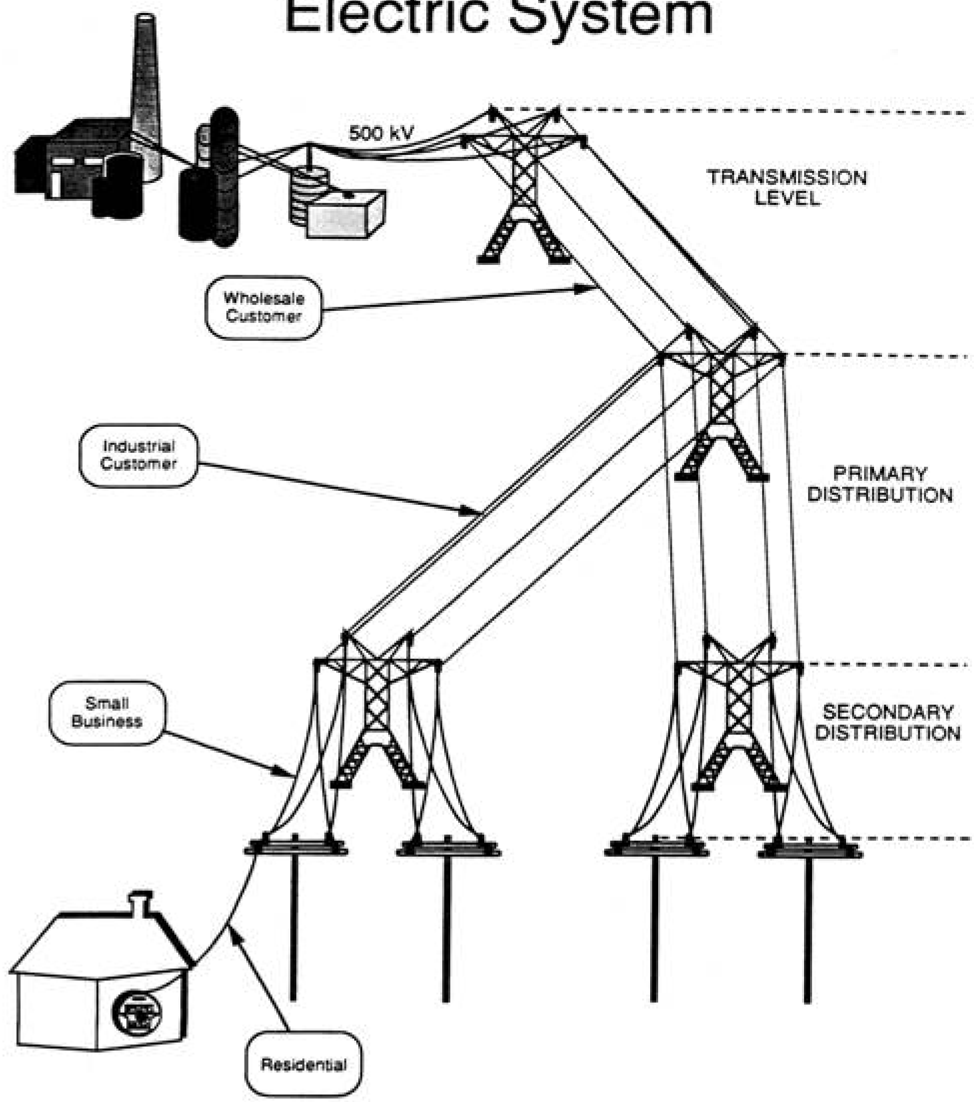
Steps in Cost Allocation



Functionalization Of Costs
Electric

Production	Transmission	Distribution	General
Generating Plant	High Voltage	Distribution Lines	Plant investment or expenses not related directly to other functions
Generation O&M	Transmission Lines	Distribution Substations	
Fuel Cost	Transmission O&M	Line Transformer	
Purchased Power	Transmission Stations	Meters	
		Service	

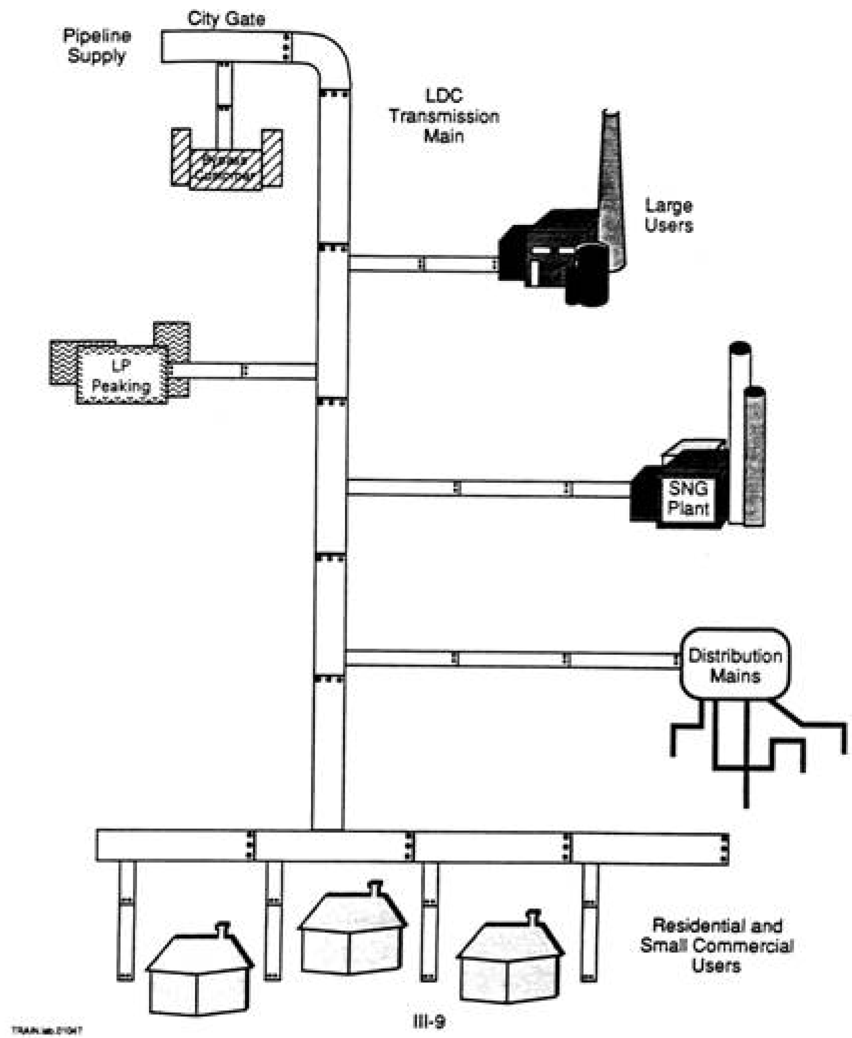
Electric System



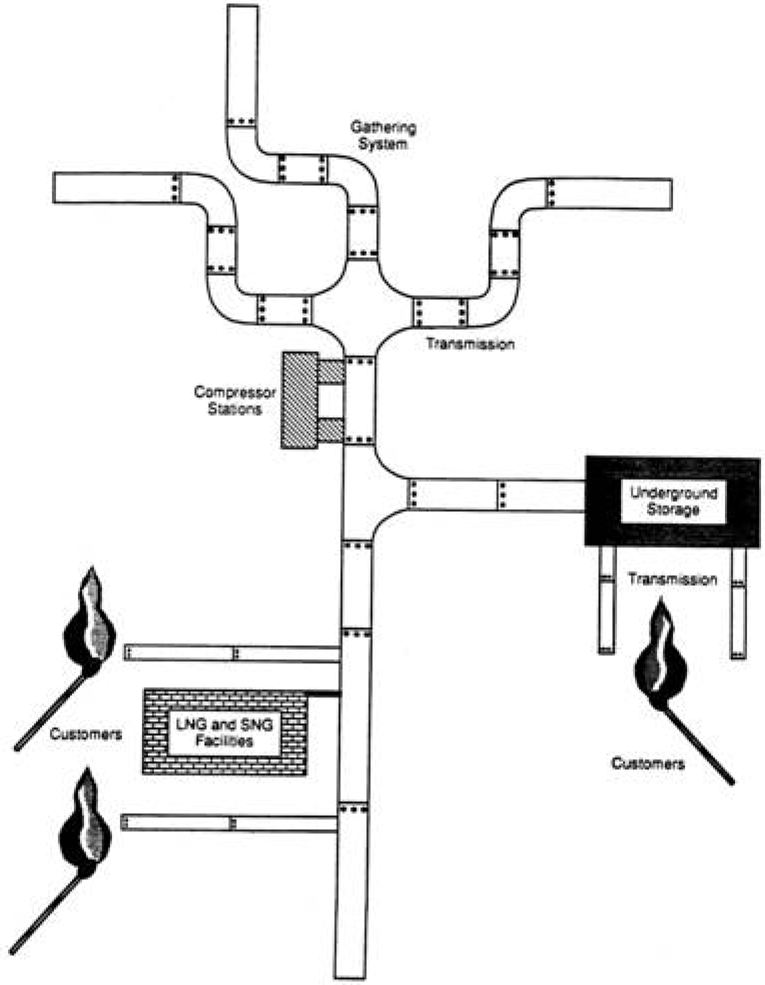
Functionalization Of Costs
Gas Systems

Production	Storage	Transmission	Distribution	General
Pipeline demand charges	Underground storage	High pressure long distance gas transportation	Transporting gas to ultimate customers	Plant investment or expenses not related directly to other functions
Peaking facilities	Local storage			
SNG or LNG plant				

Gas Distribution System



Pipeline System



III-10

Cost of Service - Functionalization

- What is the cost function?
- Functionalization identifies the costs attributable to the provision of service, excluding non-utility or other utility service items
- Groups costs according to the particular function i.e.

  Electric – Generation, Transmission, Distribution

  Gas – Production, Gathering, Transmission, Distribution

Cost of Service - Functionalization

- ✓ Uniform System of Accounts classifies most cost items
- ✓ Other items such as income taxes, cost of capital, and administrative costs must be allocated within these functions

Cost of Service - Classification

✓Functionalized costs are classified as being either Fixed or Variable Costs

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Fixed and Variable Cost

Fixed costs relate to providing installed capacity. Generally fixed costs have been allocated based on a demand measure rather than an energy or commodity measure. This is, however, not exclusively true. Examples of deviations are:

1. Electric - Average and Excess Allocation
2. Electric - System Planning Allocation - BIP Equivalent Peaker
3. Gas Pipeline - Atlantic Seaboard - 50% Demand/50% Commodity
4. Gas Pipeline - United - 25% Demand/75% Commodity
5. Recent Gas Pipeline Policy - Minimize Commodity Charge

Cost of Service – Cost Classification

- Three types of Classified Costs
- Demand/Capacity Costs
- Commodity/Energy Costs
- Customer Costs

Cost of Service – Cost Classification

- Demand/Capacity Costs are those costs which include capital and operating expenses incurred to provide sufficient capacity to meet peak demand. These costs are not affected by the number of customers or annual usage, but rather are put in place to service customers at the time of maximum usage

Cost of Service - Cost Classification – Demand Costs

- ✓ An example of demand cost classification would be transmission plant constructed to provide service to meet the peak demand…all capital and operating expenses associated with the construction and maintenance of this facility would be considered demand costs

Cost of Service – Cost Classification – Commodity Costs

- Commodity/Energy Costs are those costs that vary in direct proportion to the volume of service consumed. These costs are not related to capacity or customer costs
- An example of Commodity costs are the purchased natural gas volumes transported through interstate pipelines utilizing fixed demand (capacity costs)

Cost of Service – Cost Classification – Customer Costs

- Customer Costs are those costs that are affected directly by the number of customers served regardless of usage. Such costs include meters, meter reading, billing, and some portion of the distribution system
- Normally, the customer charge recovers customer related costs

Determination of Customer Related Costs

Plant

- Meters
- Service Extension
- Minimum Grid
- Zero Intercept

Expenses

- Meter Reading
- Customer Accounting
- Customer Service

Classification of Costs

Classification

Function		Demand	Energy	Customer
	Production	X	X	
	Transmission	X		
	Distribution	X		X
	General			X

Cost of Service – Cost Classification

- Traditionally, one of the most contentious issues concerning cost of service is the classification of costs between capacity, energy, and customer costs
- No right or wrong – judgment must be used to resolve these disputes

Cost of Service – Cost Classification

Example

In the gas industry, distribution mains comprise the largest single capital investment of the utility. There are elements of all three classifications in this cost category. Distribution mains carry energy and should be classified as an energy cost. However, the size of the distribution mains installed is determined by the peak design day. Therefore they are demand related. Finally, the number of customers also determines how extensive the distribution main system extends. Thus, they are also customer related. The key question then becomes: What portion of the distribution mains account should be classified as demand, energy, and customer related?

Cost of Service - Cost Classification

- Classification of costs is largely a matter of judgment
- Parties litigating rate cases have proposed distribution mains as 50% energy related and 50% customer related
  –
- This type of classification reduces the distribution mains allocation to industrial customers
- OCA normally supports 50% demand related and 50% energy related
- This type of classification places more burden on the industrial customers and shifts costs away from residential customers

Table IV-A

Classification Between Energy and Demand Related Costs

Classification of Rate Base

FPC Uniform System of Account Nos.	Description	Demand Related	Energy Related	Customer Related
	Production Plant			
301-303	Intangible Plant	X	-	-
310-316	Steam Production	X	-	-
320-325	Nuclear Production	X	-	-
330-336	Hydraulic Production	X	X[2]	-
340-346	Other Production	X		-
	Transmission Plant			
350-359	All Transmission Accounts	X	-	-
	Distribution Plant			
360	Land & Land Rights	X	-	X
361	Structures & Improvements	X	-	X
362	Station Equipment	X	-	-
363	Storage Battery Equipment	X	-	-
364	Poles, Towers & Fixtures	X	-	X
365	Overhead Conductors & Devices	X	-	X
366	Underground Conduit	X	-	X
367	Underground Conductors & Devices	X	-	X
368	Line Transformers	X	-	X
369	Services	-	-	X
370	Meters	-	-	X
371	Installations on Customer Premises	-	-	X
372	Leased Property on Customer Premises	-	-	X
373	Street Lighting & Signal Systems	-	-	-
	General Plant			
389-399	All General Plant Accounts	X	-	X
	Material & Supplies			
151	Fuel	X	-	-
152-174	Other	X	-	X

1. Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

2. In some instances, a portion of hydro rate base may be classified as energy-related.

Excerpted from NARUC, Electric Utility Cost Allocation Manual, 1973.

Cost of Service – Cost Classification

- PA PUC does not have a definitive classification method
- Remember that a cost of service study is only a ratemaking guide or tool

Cost of Service – Cost Allocation

- ✓ Once the costs are functionalized and classified, the final step is to allocate the costs among the various customer classes
- ✓ Direct Allocation – known costs that are incurred on behalf of one customer or class of customers should be directly assigned to that customers or class
- ✓ For example – Uncollectible Expenses are normally incurred by residential customers

Cost of Service – Cost Allocation

- For costs that cannot be directly assigned, then customer class ratios are developed to allocate the remaining costs

Cost of Service – Cost Allocation

Example of class ratios

Class	#Customers	Ratio to Total
R	75	.75
C	15	.15
I	10	.10
Total	100	1.00

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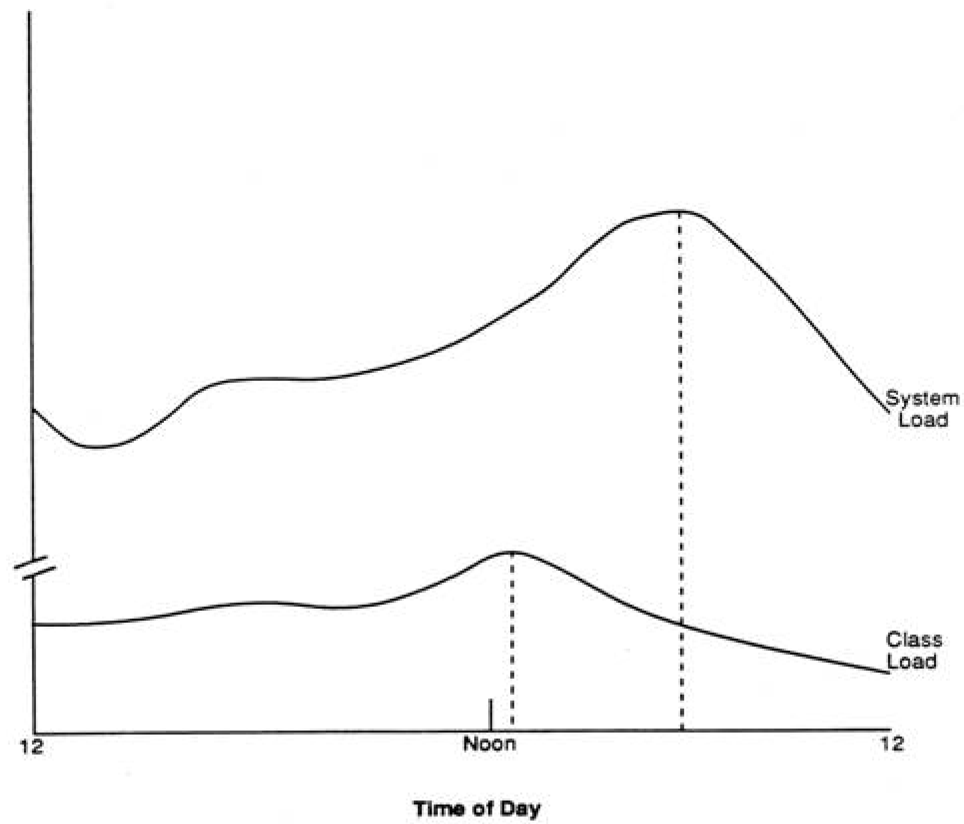
Cost of Service – Cost Allocation

In this example, if the costs were classified as customer related costs, then the residential customer class would be allocated 75% of all customer identified and classified costs that are not directly assigned

Understanding the Nature of Customer Demand



Cost Allocation Guidelines

Cost causation

Why was plant installed?

Why was expense incurred?

What measure of system usage best captures cost causation?

Allocating Costs to Customer Classes

(Commonly Used Allocation Methods)

Demand Costs

Coincident Peak Method

Twelve Month Coincident Peak

Average and Excess

Class Coincident Peak Method

Maximum Non-Coincident Demand

Energy Costs

Energy Usage

Time Differentiated Energy Usage

Customer Costs

Customers

Weighted Customers

Frequently Contested And Unresolved Allocation Issues

- Allocation of Fixed Cost of Base Load Generation
- Determination of Customer Related Costs
- Allocation of Take or Pay Costs
- Appropriate Measure for Demand Allocation
- How to Apply Results
- Normalization

Summary

Essential Steps in Cost Allocation

- Define Classes
- Detail Investment and Expenses
- Decide on Appropriate Allocator for Each Investment or Expense
- Determine Allocator from Load Research Data
- Perform Calculations

Jurisdictional Allocation

Objective is to fairly and fully allocate overall revenue requirements to jurisdictions.

Examples are:

Utilities providing service to an regulated by commissions in more than one state.

Utilities providing wholesale service which is regulated by the FERC and retail service which is regulated by states.

Rate cases are at different times.

Cost allocation is primary method of allocating revenue requirements.

Direct assignment may be appropriate.

Revenue offset used in some cases.

Cost of Service – Cost Justification

- A company's revenue allocation is cost justified when all of the customer classes are moving towards the average system rate of return
- Gradualism and rate shock are considerations when examining customer class returns

PFG GAS, INC. AND NORTH PENN GAS COMPANY

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PRESENT RATES

Item (1)	Cost of Service (2)	Residential Service (3)	General Service - Small (4)	General Service - Large (5)	Large Volume Service (6)	Storage Service (7)
1. Revenues From Sales and Transportation	$111,768,837	$60,294,113	$33,169,745	$4,062,072	$9,127,295	$5,115,612
2. Other Revenues	475,000	301,691	71,100	21,397	53,934	26,878
3. Total Operating Revenues	112,243,837	60,595,804	33,240,845	4,083,469	9,181,229	5,142,490
4. Less: Operating Expenses	99,361,197	59,822,746	28,790,872	2,167,565	5,876,416	2,703,598
5. Return and Income Taxes	12,882,640	773,058	4,449,973	1,915,904	3,304,813	2,438,892
6. Less: Interest Expense	6,113,253	2,721,009	1,097,940	471,943	1,164,575	657,786
7. Taxable Income	6,769,387	(1,947,951)	3,352,033	1,443,961	2,140,238	1,781,106
8. Less: Income Taxes	2,982,204	(858,278)	1,476,787	636,104	942,973	784,618
9. Net Return (Ln 5 - Ln 8)	9,900,436	1,631,336	2,973,186	1,279,800	2,361,840	1,654,274
10. Original Cost Measure of Value (Factor 16.)	163,713,344	72,860,975	29,410,991	12,635,209	31,191,679	17,614,490
11. Rate of Return, Percent	6.05%	2.24%	10.11%	10.13%	7.57%	9.39%
12. Relative Rate of Return	1.00	0.37	1.67	1.67	1.25	1.55

Schedule B

PFG GAS, INC. AND NORTH PENN GAS COMPANY

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PROPOSED RATES

Item (1)	Cost of Service (2)	Residential Service (3)	General Service - Small (4)	General Service - Large (5)	Large Volume Service (6)	Storage Service (7)
1. Revenues From Sales and Transportation	$126,169,599	$70,035,046	$35,202,222	$4,926,184	$10,535,216	$5,470,931
2. Other Revenues	475,000	293,040	72,773	22,857	56,996	29,334
3. Total Operating Revenues	126,644,599	70,328,086	35,274,995	4,949,041	10,592,212	5,500,265
4. Less: Operating Expenses	100,067,788	60,091,880	28,926,612	2,229,762	6,027,055	2,792,479
5. Return and Income Taxes	26,576,811	10,236,206	6,348,383	2,719,279	4,565,157	2,707,786
6. Less: Interest Expense	6,113,253	2,721,009	1,097,940	471,943	1,164,575	657,786
7. Taxable Income	20,463,558	7,515,197	5,250,443	2,247,336	3,400,582	2,050,000
8. Less: Income Taxes	8,664,079	3,181,450	2,223,203	951,316	1,439,970	868,141
9. Net Return (Ln 5 - Ln 8)	17,912,732	7,054,756	4,125,180	1,767,963	3,125,187	1,839,645
10. Original Cost Measure of Value (Factor 16.)	163,713,344	72,860,975	29,410,991	12,635,209	31,191,679	17,614,490
11. Rate of Return, Percent	10.94%	9.68%	14.03%	13.99%	10.02%	10.44%
12. Relative Rate of Return	1.00	0.88	1.28	1.28	0.92	0.95

Schedule C

Pricing Theory

- Accessibility
- Availability
- Acceptibility
- World Energy Council

Pricing Theory

- The purpose of an economic system is to allocate limited resources for the production and consumption of goods and services to meet the needs of all sectors in the economy

Pricing Theory

The failure of markets to allocate resources efficiently provides reasons to examine other cost of service mechanisms to induce markets to function efficiently

Pricing Theory

- Two common market interventions:
  - ✓Taxes
  - ✓Subsidies

Pricing Theory

A consistent and stable energy policy founded with long term goals that fosters clear rules is the goal of every regulator

Pricing Theory

- Primary challenge in developed countries is to reduce prices to the competitive cost of service
- Primary challenge in developing countries is to set prices high enough to cover the full cost of delivering the service and ensure the payment is collected

Pricing Theory

- Accessibility is the provision of reliable and affordable modern energy services to all households
- Meeting the needs of the poor
- Accelerate economic growth

Pricing Theory

- Availability refers to quality and reliability of delivered energy
- Allow a reasonable return on generation investment
- Provide incentives to maintain and expand deliveries to people who do not have access

Pricing Theory

- ✓ Acceptability addresses environmental goals and public attitudes
- ✓ Reduce local pollution
- ✓ Price energy choices to eliminate inefficient energy choices ie. Price electricity so that kerosene or wood products are too costly

Prices – Regulators vs. Cost of Service

- Economic Regulator requirements are defined by the economic, social and energy policies that a government applies to planning and decision making process
- Government encourages private or public consumption of energy from a certain source, ie. Iran's government subsidizes natural gas in order to free additional oil for export

Prices - Regulators vs. Cost of Service

Policy continued…..

- Government might establish policies to provide access to energy through subsidized tariffs
- Market based competitive pricing versus the basic human need for electricity whether or not its full costs are recovered

Prices – Regulators vs. Cost of Service

- Cost of Service Argument
- Cost Causation
- Load Factor Allocation
- Allocating costs based on generation, transmission, distribution, and supply
- Less arbitrary but may not take into account the overall social need

Prices – Regulators vs. Cost of Service

- ✓ Soft Cost Issues
- ✓ Result from losses in the energy chain such as metering problems, meter by-pass, tampering, illegal connections to the grid, collection problems and non-payment of bills

Prices – Regulators vs. Cost of Service

- Soft Costs explain why some energy suppliers are financially nonviable, even when tariffs are based on cost of service
- Soft Costs can negatively affect reliability of delivered services

Prices - Regulators vs. Cost of Service

- Subsidies
- How to calculate
- Rate of return of one customer class less than system average
- Justified on grounds of equity or of efficiency

Prices - Regulators vs. Cost of Service

Subsidies

- ✓ May distort prices and incentives and lead to non-optimal consumption and production patterns
- ✓ Reduce economic efficiencies
- ✓ May be necessary to meet human needs

Prices - Regulators vs. Cost of Service

- Three Criteria for Subsidy Programs
- "Efficiency" represents the welfare gain for the consumer balanced against its distorting effects and the cost of the subsidy ….perform cost benefit analysis

Prices - Regulators vs. Cost of Service

Three Criteria for Subsidy Programs

- “Targeting” - subsidies go to the sector that need them
- Be careful that you hit your target, unintended consequences

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Prices – Regulators vs. Cost of Service

Three Criteria for Subsidy Programs

- ✓ "Administrative Cost" is the cost to put subsidy in place and manage the subsidy, including monitoring

Rate Structure

- The next step in the conventional cost of service ratemaking process is the determination of a specific rate structure
- Three types of rate structure:
  - Marginal Cost Pricing
  - Opportunity Cost Pricing
  - Market Pricing

Rate Structure

- Marginal Cost Pricing

  The optimal allocation of resources is reached when marginal price is equal to marginal cost

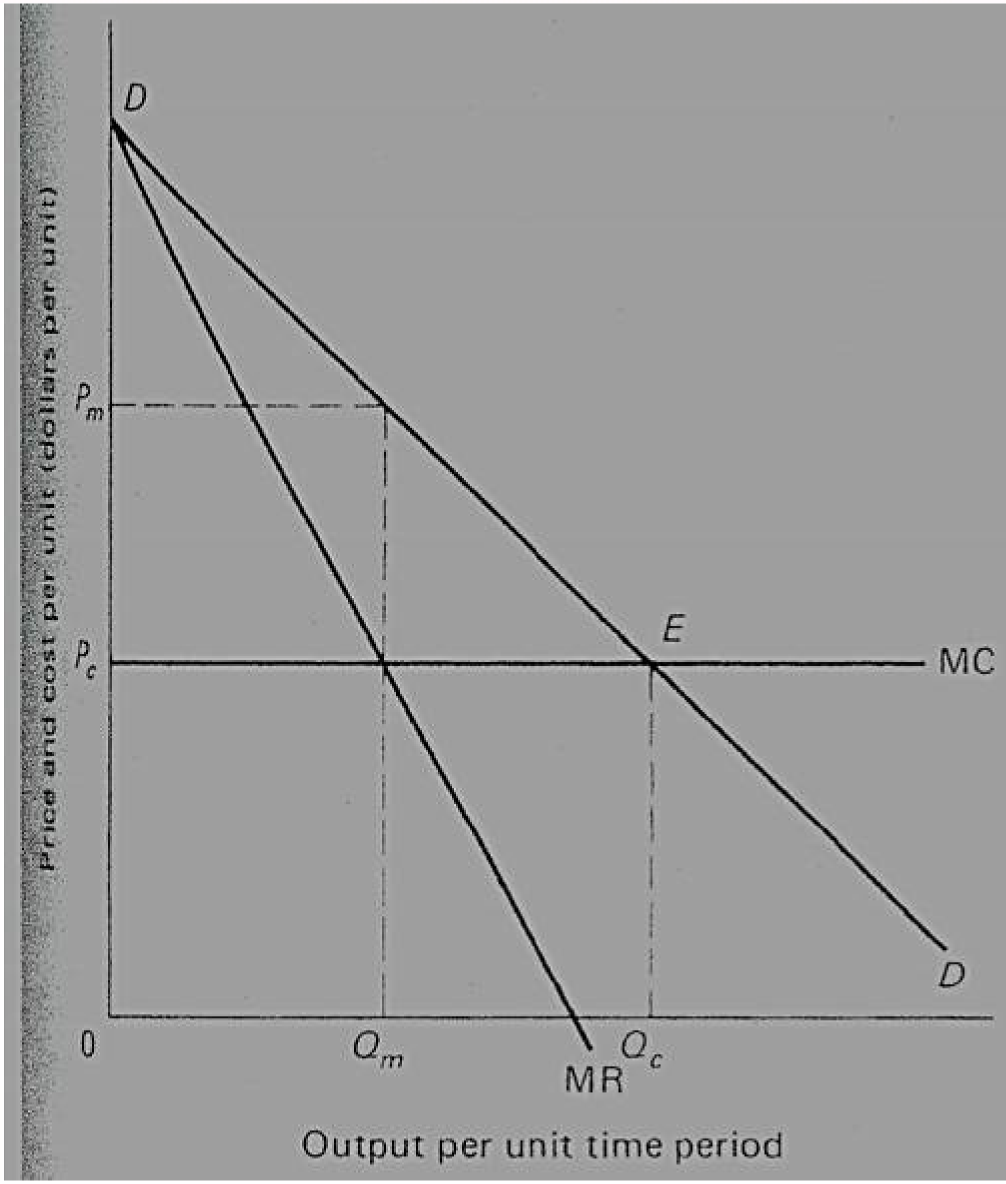

FIGURE 5-2
Comparing price and output for monopoly in competition. Assume constant marginal cost for the industry. Given an industry demand curve *DD*, and assuming that the industry supply curve is MC, the competitive industry output would be Q_c; the industry price would be P_c. Now consider the possibility that all firms become a single-monopoly firm overnight and that there are no changes in costs. The profit-maximizing rate of output will now fall to Q_m; the price will go up to P_m. The conclusion is that monopolization of a perfectly competitive industry restricts production and increases price, *ceteris paribus*.

Marginal Cost Pricing Advantages

- Final prices will not be perfect in a market clearing sense, but can be used as a benchmark
- Useful in determining rate structure – the allocation of costs among various customer classes

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Marginal Cost Pricing

- Prices based on Total Costs ignore the long-run marginal cost that may be many times greater than current average cost

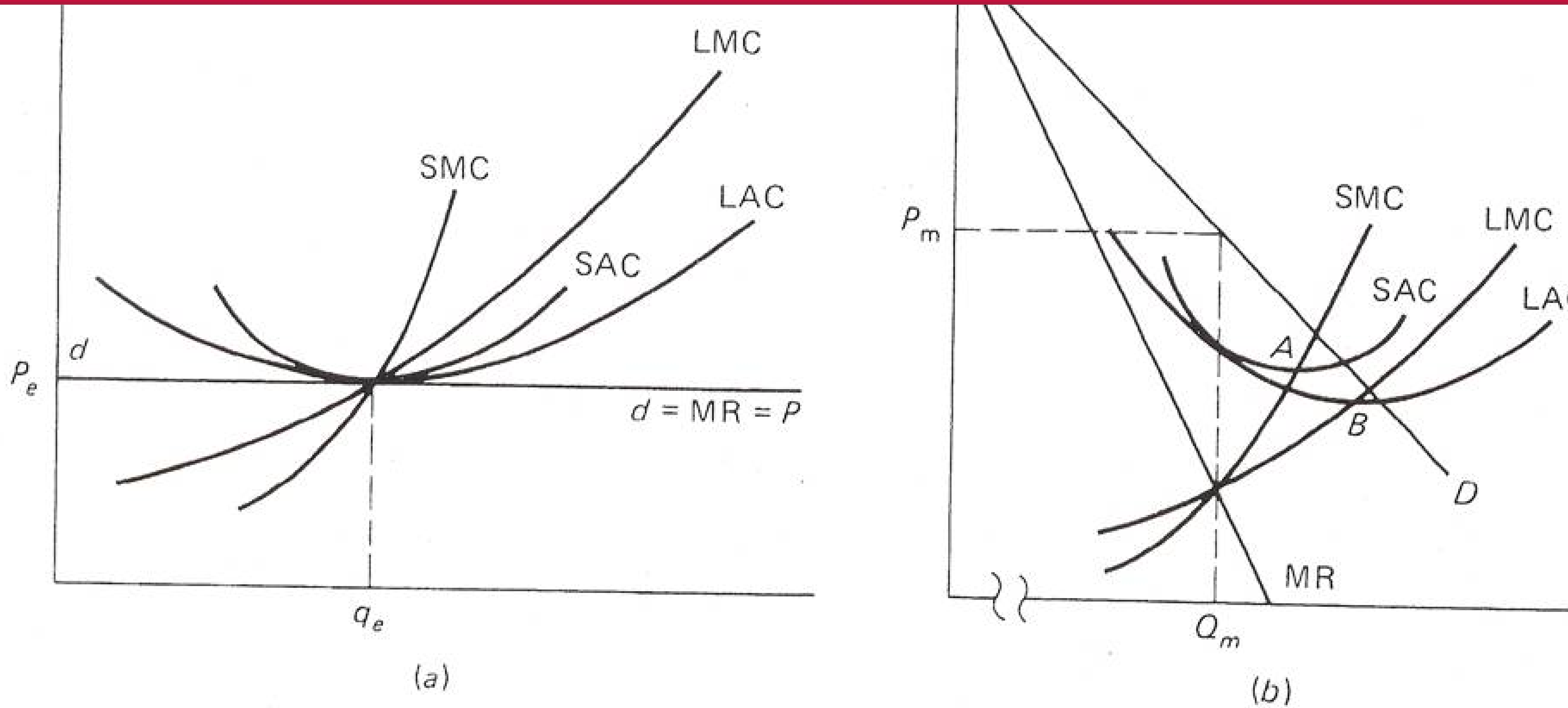

FIGURE 5-1

Comparing monopoly and competitive costs. In panel (*a*) we show long-run equilibrium for a perfectly competitive firm. Its rate of output q_e is such that SMC = SAC = LAC = LMC = MR = P. Moreover, average total cost is at a minimum. In panel (*b*) we show the situation fc a monopolist. At the profit-maximizing rate of output Q_m, the monopolist is not operating at the minimum point A on its short-run average cost curve SAC, nor at the minimum point B or its LAC curve.

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MC Pricing

- An electric utility that must expand in order to satisfy the demand at the current regulated price may have to incur costs that are many times greater than it paid in the past

MC Pricing

- The long run marginal cost of electricity is 5-10 times the price currently charged for it
- If electricity consumers are not charged a price that reflects true, long run marginal costs of providing additional generation, then the quantity demanded by consumers will be greater than it would be otherwise
- LRMC pricing may exceed fair ROR – LRMC >average costs by great amount

Opportunity Cost Pricing

- Opportunity Cost pricing is based on the value the energy would have if it could be offered and purchased outside the country rate than consumed within
- Sanity check – make sure internal pricing not out of line

Market Pricing

- Markets are the most efficient method to allocate resources
- Do no always provide affordable access to energy for the poorest people

Ratemaking Solutions

- Baseline Tariffs – lower rates up to a certain level of consumption
- Loans for 4-5 year periods to allow consumers to pay for connection charges
- Direct participation by local officials in the management of the system – helps to keep non technical losses (soft costs) to a minimum

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Observations by 2001 World Energy Council

- Pricing structures and subsidies which are not carefully designed create distortions
- Pricing should be related to costs
- Subsidies often go to unintended customer classes
- Non-technical losses and non-collection rates are too high

Principles on Pricing Energy in Developing Countries

- Prices should be set at a level which allows energy providers to recover the long run marginal cost of delivering service including a fair return on investment
- Utilize cost of service tools to calculate the long run marginal cost of delivering energy to each customer class

Principles on Pricing Energy in Developing Countries

- Pro's - Marginal cost pricing is useful in optimizing the allocation of resources
- Con's – Higher tariffs may result and could be detrimental to a country's industrial competitiveness or might deprive lower income consumers of an essential service

Principles on Pricing Energy in Developing Countries

- Metering, Billing, and Collection
- Customer charge components
- Deficiencies in metering energy consumed, billing the energy delivered, and collection payment is a major issue in developing countries
- Need to reduce non-technical losses (soft costs)

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TABLE 4-1

***CLASS MW DEMANDS AT THE GENERATION LEVL IN THE TWELVE* MONTHLY SYSTEM PEAK HOURS**

(1988 Example Data)

Rate Class	January	February	March	April	May	June	July	August
DOM	3,887	3,863	2,669	2,103	2,881	3,338	4,537	4,735
LSMP	3,065	3,020	3,743	4,340	4,390	4,725	5,106	5,062
LP	2,536	2,401	2,818	2,888	3,102	3,067	3,219	3,347
AG&P	84	117	144	232	405	453	450	447
SL	94	105	28	0	0	0	0	0
Total	9,666	9,506	9,402	9,563	11,318	11,583	13,312	13,591

Rate Class	September	October	November	December	Total	Average
DOM	4,202	2,534	3,434	4,086	42,268	3,522
LSMP	5,106	4,736	3,644	3,137	50,614	4,218
LP	3,404	3,170	2,786	2,444	35,181	2,932
AG&P	360	284	138	75	3,189	266
SL	0	0	103	126	457	38
Total	13,072	10,724	10,105	9,868	131,709	10,976

Note: The rate classes and their abbreviations for the example utility are as follows:

DOM - Domestic Service
LSMP - Lighting, Small and Medium Power
LP - Large Power
AG&P - Agricultural and Pumping
SL - Street Lighting

TABLE 4-2

CLASS MW DEMANDS AT THE GENERATION LEVEL IN THE 3 SUMMER AND 3 WINTER SYSTEM PEAK HOURS

(1988 Example Data)

	Winter				Summer			
Rate Class	January	February	December	Average	July	August	September	Average
DOM	3,887	3,863	4,086	3,946	4,537	4,735	4,202	4,491
LSMP	3,065	3,020	3,137	3,074	5,106	5,062	5,106	5,092
LP	2,536	2,401	2,444	2,460	3,219	3,347	3,404	3,323
A&P	84	117	75	92	450	447	360	419
SL	94	105	126	108	0	0	0	0
Total	9,666	9,506	9,868	9,680	13,312	13,591	13,072	13,325

TABLE 4-3

DEMAND ALLOCATION FACTORS

Rate Class	MW Demand At Annual System Peak (MW)	1 CP Alloc. Factor (Percent)	Average of the 12 Monthly CP Demands (MW)	12 CP Alloc. Factor (Percent)	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	3S/3W Alloc. Factor (Percent)	Noncoinc. Peak Demand MW	NCP Alloc. Factor (Percent)
DOM	4,735	34.84	3,522	32.09	4,491	3,946	36.67	5,357	36.94
LSMP	5,062	37.25	4,218	38.43	5,092	3,074	35.50	5,062	34.91
LP	3,347	24.63	2,932	26.71	3,323	2,460	25.14	3,385	23.34
AG&P	447	3.29	266	2.42	419	92	2.22	572	3.94
SL	0	0.00	38	0.35	0	108	0.47	126	0.87
Total	13,591	100.00	10,976	100.00	13,325	9,680	100.00	14,502	100.0

Note: Some columns may not add to indicated totals due to rounding.

TABLE 4-4

ENERGY ALLOCATION FACTORS

Rate Class	Total Annual Energy Used (MWH)	Total Energy Allocation Factor (%)	On-Peak Energy Cons. (MWH)	On-Peak Energy Allocation Factor (%)	Off-Peak Energy Cons. (MWH)	Off-Peak Energy Allocation Factor (%)
DOM	21,433,001	30.96	3,950,368	32.13	17,482,633	30.71
LSMP	23,439,008	33.86	4.452,310	36.21	18,986,698	33.35
LP	21,602,999	31.21	3,474,929	28.26	18,128,070	31.85
AG&P	2,229,000	3.22	335,865	2.73	1,893,135	3.33
SL	513,600	0.74	80,889	0.66	432,711	0.76
Total	69,217,608	100.00	12,294,361	100.00	56,923,247	100.00

Note: Some columns may not add to indicated totals due to rounding.

TABLE 4-5

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SINGLE COINCIDENT PEAK METHOD

Rate Class	MW Demand at Generator at System Peak	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	*4,735*	*34.84*	*369,461,692*
LSMP	5,062	37.25	394,976,787
LP	3,347	24.63	261,159,089
AG&P	447	3.29	34,878,432
SL	0	0.00	0
TOTAL	13,591	100.00	$ 1,060,476,000

TABLE 4-6

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SUMMER AND WINTER PEAK METHOD

Rate *Class*	Average of the 3 Summer CP Demands *(MW)*	Average of the 3 Winter CP Demands *(MW)*	Demand Allocation *Factor*	Total Class Production Plant Revenue *Requirmt*
DOM	4,491	3,946	36.67	388,925,712
LSMP	5,092	3,074	35.50	376,433,254
LP	3,323	2,460	25.14	266,582,600
AG&P	419	92	2.22	23,555,889
SL	0	108	0.47	4,978,544
TOTAL	13,325	9,680	100.00	$ 1,060,476,000

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TABLE 4-7

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE TWELVE COINCIDENT PEAK METHOD

Rate Class	Average of 12 Coincident Peaks At Generator (MW)	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,522	32.09	$ 340,287,579
LSMP	4,218	38.43	407,533,507
LP	[illegible]	26.71	[illegible]
AG&P	[illegible]	2.42	[illegible]
SL	38	0.35	3,671,473
TOTAL	[illegible]	100.00	$ [illegible]

...ate ...lass			M...
...OM	3,887	3,863	
...MP	3,065	3,020	
...	2,536	2,401	
...G&P	84	117	
...	94	105	

TABLE 4-8

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE ALL PEAK HOURS APPROACH

Rate Class	Class On-Peak MWH At Generation	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,950,368	32.13	340,747,311
LSMP	4,452,310	36.21	384,043,376
LP	3,474,929	28.26	299,737,319
AG&P	335,865	2.73	28,970,743
SL	80,889	0.66	6,977,251
TOTAL	12,294,361	100.00	$ 1,060,476,000

Notes: The on-peak periods for the example utility are from 5:00 p.m. to 9:00 p.m. on weekdays in January through May and October through December, and from 12:00 noon to 6:00 p.m. on weekdays in June through September. Some columns may not add to indicated totals due to rounding.

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TABLE 4-9

SUMMARY OF ALLOCATION FACTORS AND REVENUE RESPONSIBILITY FOR PEAK DEMAND COST ALLOCATION METHODS

	1 CP Method		3 Summer and 3 Winter Peak Method	
Rate Class	**Allocation Factor (%)**	**Revenue Requirement**	**Allocation Factor (%)**	**Revenue Requirement**
DOM	34.84	369,461,692	36.67	388,925,712
LSMP	37.25	394,976,787	35.50	376,433,254
LP	24.63	261,159,089	25.14	266,582,600
AG&P	3.29	34,878,432	2.22	23,555,889
SL	0.00	0	0.47	4,978,544
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

	12 CP Method		All Peak Hours Approach	
Rate Class	**Allocation Factor (%)**	**Revenue Requirement**	**Allocation Factor (%)**	**Revenue Requirement**
DOM	32.09	340,287,579	32.13	340,747,311
LSMP	38.43	407,533,507	36.21	384,043,376
LP	26.71	283,283,130	28.26	299,737,319
AG&P	2.42	25,700,311	2.73	28,970,743
SL	0.35	3,671,473	0.66	6,977,251
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

Note: Some columns may not add to totals due to rounding.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	.2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Cost of Service

Reference Material

- “Gas Rate Fundamental” 1987 Edition
- “Industrial Organization”, Clarkson, Miller, 1982
- “Pricing Energy in Developing Countries”, 2001 World Energy Council
- “Electric Utility Cost Allocation Manual”, 1992, NARUC