Indiana Utility Regulatory Commission

An Overview of Ratemaking

Laura Cvengros

Assistant Director Electricity Division

November 23, 2004

An Overview of Ratemaking

History

- Evolution of Price Regulation
- Goals of Price Regulation

Cost of Service Analysis

- Revenue Requirements
- Rate Base
- Rate of Return

An Overview of Ratemaking – cont.

- Functionalization
- Classification
- Allocation

History

Early Development (1879 – 1917)

- Thomas Edison invents the first commercially viable electric lamp. (1879)
- September 4, 1882, Pearl Street Station in New York City provides electricity to 400 lamps with a generating capacity of 560 kW.
- 1886 – George Westinghouse perfects a practical alternating current system. With “step up” and “step down” transformers electricity can be transmitted greater distances.
- By 1907, 45 electric lights firms had the legal right to operate in Chicago.
- The number of electric systems steadily increased up to 1917 when decline set in.

History

Consolidation (1920s)

Holding Companies:

- Advantages:
  - Economies of Scale – generation facilities, financing, engineering and construction expertise, purchasing power
  - Profit Motive – A small investment could provide a controlling interest in a large number of companies and a large return on investment.

History – cont.

- Disadvantages:
  - Pyramiding
  - Write-ups
  - Intracompany Transactions

History – cont.

Federal Power Act of 1935

- Title I – SEC authority over mergers and acquisitions and to proscribe the form and manner of account for holding companies
- Title II – FPC (FERC) authority over the interstate transmission and sale at wholesale of electricity.

History – cont.

The "Golden Age" of the Electric Power Industry: (1945 – 1970)

- Tremendous gains in generation efficiencies through larger power plants
- High growth in electricity demand (7-8% annually)
- Low inflation rates; low financing costs
- Falling real and nominal electricity prices
- Rate increases seldom necessary

History – cont.

Decade of Turmoil: 1970s

- Environmental movement
- Arab oil embargo
- Fuel prices increases
- High inflation; high cost of capital
- Meltdown of the “to cheap to meter” nuclear dream

History – cont.

Catalysts Driving Regulatory and Industry Structural Change in the 1980s

- Public disillusion with nuclear power
- Successful integration of QFs
- Competitive bidding for new generation
- Utility generation affiliates

History – cont.

Energy Policy Act of 1992

FERC Orders 888 (RTO) and 889 (OASIS)

State Retail Competition Initiatives

FERC Order 2000

Electric Industry Scandals and Market problems (ERON, California)

August 2003 Blackout

Usual Goals of Utility Regulation

Avoid “undue” price discrimination

Prevent excessive profits

Assure availability of service on “reasonable” terms to all customers (“obligation to serve”)

Assure a stable customer base to support large investments

Promote regional development and growth

Pursue related political goals and policies

Cost of Service Analysis

- Revenue Requirements
  - Expenses
  - Rate Base
  - Rate of Return
- Cost of Service Study
  - Functionalization
  - Classification
  - Allocation

Revenue Requirements Formula

- Definition:
  - Total revenues required to cover expenses and the **opportunity** to earn a fair rate of return.
  - Total cost to provide safe and reliable service to customers, i.e. cost of service concept.
- The Formula:

Revenue Requirements = Expenses + r(Rate Base)

Expenses = O&M + Depreciation + Income Taxes

r = Overall Rate of Return (WACC)

Rate Base = (Plant in Service + Working Capital) – (Accumulated Depreciation – Accumulated Deferred Income Taxes)

Revenue Requirements

- Selection of a test year.
- Adjustments for fixed, known and measurable changes
- Pro Forma test year for the determination of the new revenue requirements.

PSI ENERGY, INC.
CAUSE NO. 42359
JURISDICTIONAL FINANCIAL SUMMARY
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2002
(DOLLARS IN THOUSANDS)

DATA: 12 MONTHS ACTUAL
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED

SCHEDULE A-1
PAGE 1 OF 1
WITNESS RESPONSIBLE:
L.T. HOWE

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	JURISDICTIONAL PROPOSED TEST YEAR
1	Rate Base	A-2	$3,651,757
2	Current Operating Income	A-2	$164,528
3	Earned Rate of Return (Line 2 / Line 1)		4.51%
4	Requested Rate of Return	E-1	7.92%
5	Required Operating Income (Line 1 x Line 4)		289,219
6	Operating Income Deficiency (Line 5 - Line 2)		124,691
7	Gross Revenue Conversion Factor	C-10	1.7172700
8	Revenue Deficiency (Line 6 x Line 7)		214,128
9	Pro Forma Unbilled Revenue and Additional Customers		(13,708)
10	Revenue Increase Requested	A-2	200,420
11	Adjusted Operating Revenues	A-2	$1,251,199
12	Revenue Requirements (Line 10 + Line 11)		1,451,619

PSI ENERGY, INC.
CAUSE NO. 42359
SUMMARY OF PRO FORMA TOTAL COMPANY
NET ORIGINAL COST RATE BASE
(DOLLARS IN THOUSANDS)

DATA: "X" ACTUAL ESTIMATED
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED

SCHEDULE B-1
PAGE 1 OF 1
WITNESS RESPONSIBLE:
S. M. FARMER

Line No.	Description	Total Company Per Books At 09/30/02 (A)	Non-Utility (B)	Electric Utility Per Books (C)	Pro Forma Adjustments: Estimated Net Additions To Plant In Service Through Applicable Cutoff Dates (SCH-B-2) (D)	Estimated AFUDC Continuation & Deferred Depreciation (SCH-B-3) (E)	Fuel Stock (SCH-B-4) (F)	Emission Allowances (SCH-B-5) (G)	Materials And Supplies (SCH-B-6) (H)	Total Pro Forma Adjustments (I)	Total Company Pro Forma Utility Rate Base (J)
1	Total Electric Utility Plant	$5,543,937	$0	$5,543,937	$783,588	$0	$0	$0	$0	$783,588	$6,327,523
2	Less: Construction Work In Progress	266,624	0	266,624	0	0	0	0	0	0	266,624
3	Property Held for Future Use	459	0	459	0	0	0	0	0	0	459
4	Electric Utility Plant in Service	5,276,854	0	5,276,854	783,588	0	0	0	0	783,588	6,060,440
5	Less: Reserve for Depreciation	2,297,427	0	2,297,427	79,095	0	0	0	0	79,095	2,376,522
6	Net Electric Utility Plant in Service	2,979,427	0	2,979,427	684,491	0	0	0	0	684,491	3,663,918
7	Fuel Stock	81,479	0	81,479	0	0	(6,608)	0	0	(6,608)	74,871
8	Emission Allowances	13,478	0	13,478	0	0	0	2,667	0	2,667	16,145
9	AFUDC Continuation / Deferred Depreciation	30,539	0	30,539	0	49,050	0	0	0	49,050	79,589
10	Materials and Supplies	41,425	0	41,425	0	0	0	0	2,526	2,526	43,951
11	Total Net Electric Utility Rate Base	$3,146,348	$0	$3,146,348	$684,491	$49,050	($6,608)	$2,667	$2,526	$732,126	$3,878,474
	Memo: Rate Base Per Final Order In Cause No. 40003										$2,380,764

CINERGY CORP. (CONSOLIDATED)
CAUSE NO. 42359
RATE of RETURN SUMMARY
AS OF SEPTEMBER 30, 2003
(DOLLARS IN THOUSANDS)

DATE OF CAPITAL STRUCTURE: SEPTEMBER 30, 2003
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED

SCHEDULE E-1
PAGE 1 OF 1
WITNESS RESPONSIBLE:
R.R. REISING &
S. M. FARMER

Line No.	Description	Capitalization (A)	Capital Structure Ratio: Financial Concept (B)	Capital Structure Ratio: Regulatory Concept (C)	Cost Rate (D)	Weighted Cost Rate: Financial Concept (E)	Weighted Cost Rate: Regulatory Concept (F)	Weighted Cost Rate: Synch. Interest (G)
1	Common Equity	$1,629,306	52.91%	44.52%	11.50%	6.08%	5.12%	
2	Preferred Stock	42,343	1.37%	1.16%	6.11%	0.08%	0.07%	
3	Long Term Debt	1,408,125	45.72%	38.48%	6.84%	3.13%	2.63%	2.65%
4	Total Financial Capitalization	3,079,774	100.00%	84.16%		9.29%		
5	Deferred Income Taxes	539,844		14.75%	0.00%		0.00%	
6	Unamortized ITC - 1970 & Earlier	212		0.01%	0.00%		0.00%	
7	Unamortized ITC - 1971 & Later	30,237		0.83%	9.29%		0.08%	
8	Customer Deposits	9,377		0.25%	6.00%		0.02%	
9	Total Regulatory Capitalization	$3,659,444		100.00%			7.92%	2.65%

PSI ENERGY, INC.
CAUSE NO. 42359
JURISDICTIONAL PROFORMA INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2002
(DOLLARS IN THOUSANDS)

DATA: 12 MONTHS ACTUAL
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED

SCHEDULE A-2
PAGE 1 OF 1
WITNESS RESPONSIBLE:
L.T. HOWE

LINE NO.	DESCRIPTION	RETAIL AT CURRENT RATES (A)	PROPOSED INCREASE (B)	PRO FORMA UNBILLED REV. & ADDITIONAL CUST. (C)	RETAIL AT PROPOSED RATES (D)
1	OPERATING REVENUES				
2	Retail Revenue	$ 1,251,199	$ 200,420	$ 13,708	$ 1,465,327
3	Sales for Resale	0			0
4	Other Operating Revenue	28,915			28,915
5	Total Operating Revenues	1,280,114	200,420	13,708	1,494,242
6					
7	OPERATING EXPENSES				
8	Operation and Maintenance Expenses				
9	Production Expenses				
10	Fuel Cost	378,286			378,286
11	Purchased Power	9,519			9,519
12	Other	106,629			106,629
13	Total Production Expense	494,434	0	0	494,434
14	Transmission Expense	25,228			25,228
15	Distribution Expense	40,136			40,136
16	Customer Accounts Expense	33,772			33,772
17	Customer Service & Information Expense	115			115
18	Sales Expense	5,383			5,383
19	Administrative & General Expense	159,153	1,124	77	160,354
20	Other Expenses	0			0
21	Amortization of Deferred Expense	28,455			28,455
22	Total Operation and Maintenance Expense	786,676	1,124	77	787,877
23					
24	Depreciation Expense	223,462	0	0	223,462
25					
26	Taxes Other Than Income Taxes	59,626	2,806	192	62,624
27					
28	State Income Taxes				
29	Normal and Surcharge	12,182	16,940	1,159	30,281
30	Provision for Deferred Income Taxes	3,060			3,060
31	Provision for Deferred Income Taxes - Credit	(3,740)			(3,740)
32	Total State Income Tax Expense	11,502	16,940	1,159	29,601
33					
34	Federal Income Taxes				
35	Normal and Surcharge	38,697	62,843	4,296	105,836
36	Provision for Deferred Income Taxes	35,879			35,879
37	Provision for Deferred Income Taxes - Credit	(40,256)			(40,256)
38	Total Federal Income Tax Expense	34,320	62,843	4,296	101,459
39					
40	Total Operating Expenses	1,115,586	83,713	5,724	1,205,023
41					
42	Net Operating Income	$ 164,528	$ 116,707	$ 7,984	$ 289,219
43					
44	Rate Base	$ 3,651,757			$ 3,651,757
45					
46	Rate of Return	4.51%			7.92%

PSI ENERGY, INC.
CAUSE NO. 42359
JURISDICTIONAL PROFORMA INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2002
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Depreciation Expense	223,462	0	0	223,462
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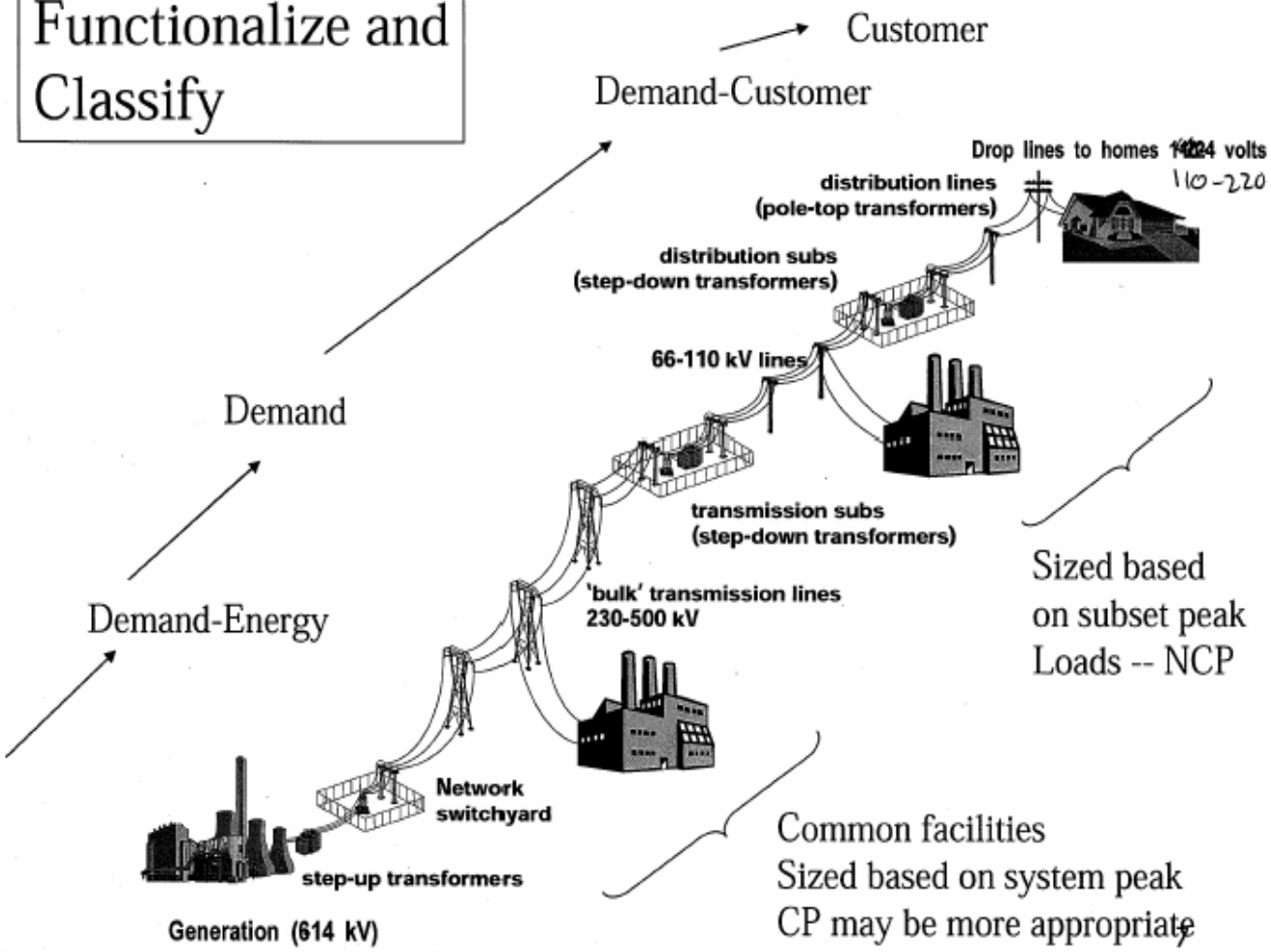
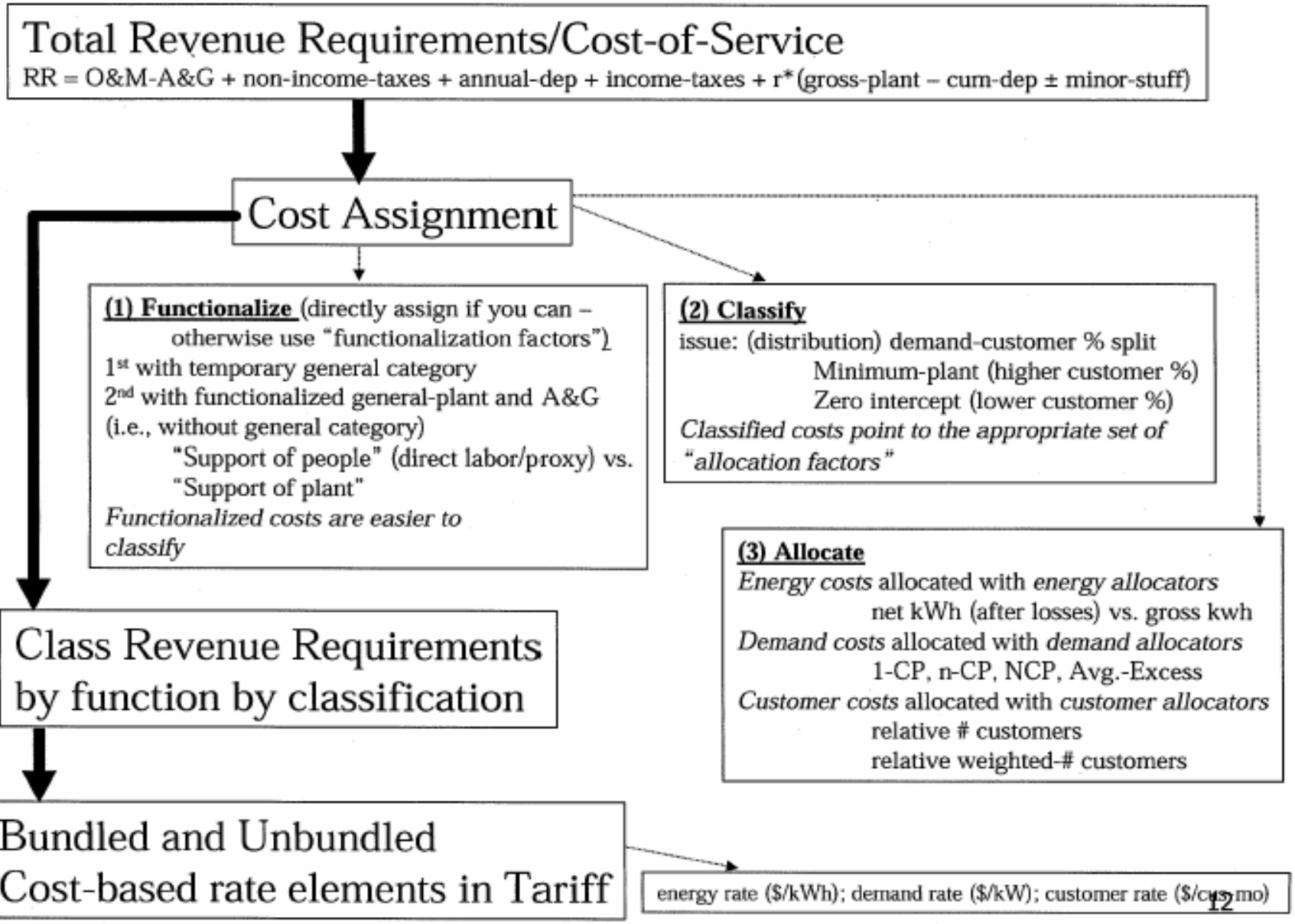
Total Operating Expenses	1,116,586	83,713	5,724	1,206,023
Net Operating Income	$ 164,528	$ 116,707	$ 7,984	$ 289,219
Rate Base	$ 3,651,757			$ 3,651,757
Rate of Return	4.51%			7.92%

Cost of Service Study

A cost of service study is a process of breaking down the revenue requirements components into operational functions and then classifying those items into energy, demand and customer related costs and then allocating the costs to the customer classes based on the concept of Cost Causation.

Functionalize and Classify




Total Revenue Requirements/Cost-of-Service
RR = O&M-A&G + non-income-taxes + annual-dep + income-taxes + r*(gross-plant – cum-dep ± minor-stuff)
Cost Assignment
(1) Functionalize (directly assign if you can – otherwise use "functionalization factors")
1st with temporary general category
2nd with functionalized general-plant and A&G (i.e., without general category)
"Support of people" (direct labor/proxy) vs. "Support of plant"
Functionalized costs are easier to classify
(2) Classify
issue: (distribution) demand-customer % split
Minimum-plant (higher customer %)
Zero intercept (lower customer %)
Classified costs point to the appropriate set of "allocation factors"
(3) Allocate
Energy costs allocated with energy allocators
net kWh (after losses) vs. gross kwh
Demand costs allocated with demand allocators
1-CP, n-CP, NCP, Avg.-Excess
Customer costs allocated with customer allocators
relative # customers
relative weighted-# customers
Class Revenue Requirements by function by classification
Bundled and Unbundled Cost-based rate elements in Tariff
energy rate ($/kWh); demand rate ($/kW); customer rate ($/cust-mo)

Indiana Utility Regulatory Commission

Rate Design Rules

Laura Cvengros

Assistant Director Electricity Division

November 24, 2004

Cost of Service to Rate Design

A Three-Step Process

- Step 1: Functionalization
- Step 2: Classification
- Step 3: Allocation

Key question to be asked at every step in the process, “What caused the cost to be incurred?”

Step 1: Functionalization

The process of dividing the total revenue requirement into functional components as related to the electric operation of the company (operating functions)

- Generation
- Transmission
- Distribution
- Meters & Services
- General

Step 2: Classification

The process of separating the functionalized costs into classifications based on the components of utility service being provided. In other words, this is the process of separating the functionalized costs into classifications that relate to what costs are sensitive to – energy generated, capacity demand or number of customers.

Cost Classification Categories

Demand-Related Costs: Those costs that vary with the kW of instantaneous demand.

- Generation costs are driven by both demand and energy requirements. All customers jointly use generation resources. Generation capacity (investment in resources) is based on the system peak demand.
- Transmission costs are driven by demand. All customers jointly use transmission resources. Transmission capacity (investment in resources) is based on the system peak demand.
- Distribution costs are driven by both demand and customer requirements. As we move further "downstream" facilities are used by a smaller subset of customers. Distribution capacity is based on the peak demand of the local customer subset.

Cost Classification Categories – cont.

Energy-Related Costs: Those costs that vary with the kWh of energy.

- Generation costs are driven by both demand and energy requirements. All customers jointly use generation resources. Variable generation operating costs are the result of energy produced by the generation resources.

Cost Classification Categories – cont.

Customer-Related Costs: Those costs that vary with the number of customers.

- Distribution costs are driven by both demand and customer requirements. As we move further "downstream" a higher share of costs are related to the provision of electric service to the individual customer.

Step 3: Allocation

The process of assigning costs to the different customer classes.

Customer Class Categories are based on such things as size of load, the voltage level at which the customer is served and other service characteristics such as whether or not the customer has a demand meter.

- The primary customer categories are Industrial (large and small) Commercial (large and small) and Residential.
- Other categories include: Agricultural, General Service, Street Lighting and Municipal.

Allocation – cont.

Once the various customer class categories have been designated, particular functionalized and classified costs are allocated among the classes based on an allocation method which is deemed the most consistent with cost causation.

- Different cost categories (demand, energy, customer) require different allocation methods.

Allocation – cont.

Demand-Related Cost Allocation Methods

- System Peak Responsibility (1CP, 4CP, 12 CP)
- Non-Coincident Peak Demand (NCP)
- Average and Excess

Energy-Related Cost Allocation Methods

- kWh of energy sold adjusted for losses

Customer-Related Cost Allocation Methods

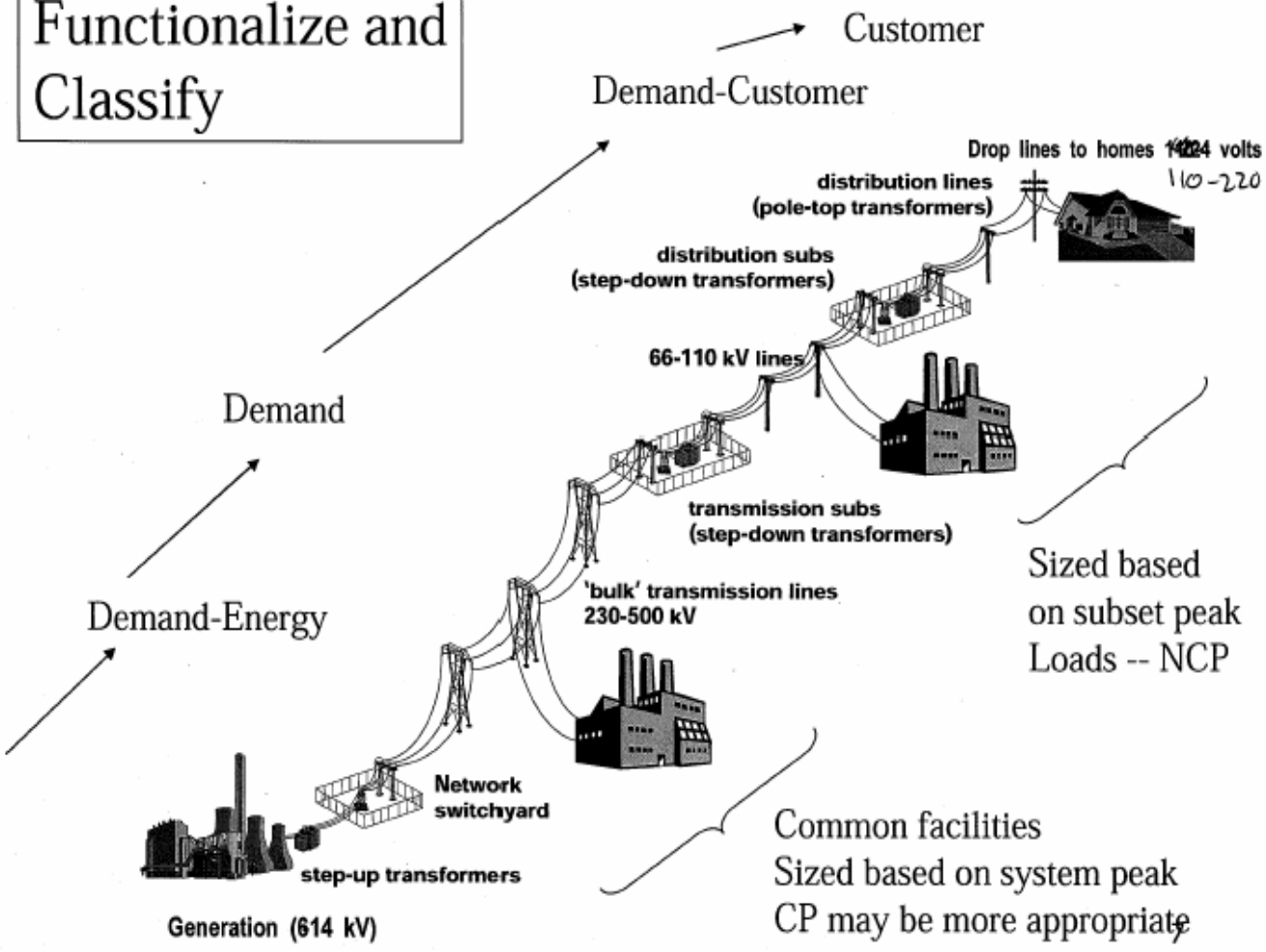
- Number of Customers

Allocation – cont.

After the functionalization step is completed, some costs can be identified as logically incurred to serve only a particular customer (or customer class). Cost-causation would dictate that these cost are only allocated to that particular customer.

After the functionalization step is completed, some costs can be identified as not being incurred by particular customer. For example, secondary distribution lines are not used to serve customers that take power at higher voltages. Cost-causation would dictate that these costs not be allocated to these particular customers.

Functionalize and Classify



Basic Cost-Based Rate Design: Bundled & Unbundled Rate Elements

The cost of service study allocates the total revenue requirement, that has been functionalized into generation, transmission and distribution costs that are, in turn, classified into demand- energy- and customer-related costs, to each rate class.

You now have a rate class specific revenue requirement that is broken down by function and classification. These are the elements necessary to design rates.

Basic Cost-Based Rate Design: Bundled & Unbundled Rate Elements – cont.

- Demand Charge: Measured in dollars per kW of monthly metered customer billing demand.
- Energy Charge: Measured in dollars per kWh of monthly customer energy use.
- Customer Charge: Measured in dollars per customer per month.

Demand Charges

- Derived by taking the demand-related costs and dividing these costs by customer class “billing demand”.
- The manner in which the demand charge is calculated must be consistent with the manner in which individual customers are metered; otherwise, the utility will over or under collect its demand related cost of the class revenue requirement.
- For a class wherein individual customers do not have demand meters, demand-related cost must be recovered either through the energy charge or the customer charge.

Energy and Customer Charges

- Energy charges are derived by taking the class energy-related costs and dividing these costs by the class energy usage.
- Customer charges are derived by taking the class customer-related costs and dividing by the class “customer months”.

Example: Residential Rates

Residential customers do not typically have demand meters therefore; We cannot put into effect a demand charge. Demand-related costs must be recovered through either the energy or customer charge.

We now calculate the unbundled rate elements by dividing each functionalized component of a classified cost by the same billing determinants. (Schedule 26)

Schedule 26
Unbundled Rates: Residential Class (Strategy II)

[A] Line No.	[B]	[C] TOTAL	[D] GEN	[E] TRANS-MISSION	[F] DISTRIBUTION DIST. SUB-STATIONS	[G] DISTRIBUTION LINES & TRANS-FORMERS	[H] DISTRIBUTION METERS & SERVICES
(1)	Demand-Related	99,308	52,849	14,524	22,223	9,713	0
(2)	Energy-Related	36,005	36,005	0	0	0	0
(3)	Customer-Related	18,342	0	0	0	5,728	12,615
(4)	Total Costs	153,656	88,854	14,524	22,223	15,441	12,615
(5)	Customer Charge ($ per month)	9.44	0.00	0.00	0.00	2.95	6.49
(6)	Energy Charge ($ per kWh)	0.07171	0.04709	0.00770	0.01178	0.00515	0.00000
	Total Class MWh	1,886,867					
	Total Class Customer-months	1,944,000					

(52,849+36,005) ÷1,886,867 = 0.04709

12,615 × 1,000 ÷1,944,000 =6.49

Multiple Block Rate Design

Rates (energy and/or demand rates) are differentiated by monthly blocks in order to achieve a pricing or social goal.

The goal of rate differentiation may be:

- More efficient use of scare resources – price tracks marginal cost
- Increased use of excess resources
- Promotion of equity and concerns regarding ability to pay
- Promotion of conservation and environmental concerns

Multiple Block Rate Design – cont.

Rate differentiation can be structured as:

- Decreasing block rate structure
- Increasing block rate structure

Rate differentiation may be based on:

- Blocks based on total usage levels
- Blocks based on levels of demand (kW)
- Blocks based on customer load factor (kWh/kW)
- Time-of-usage blocks
  - blocks of usage during periods of high system demand incur higher prices
- Decreasing block rate structure – rate decrease with successively higher usage blocks

Examples of Block Rates

Residential RATE: (IPL)
The sum of the Customer Charge and Energy Charge shown hereafter.

Customer Charge

- For bills of 0-325 KWH per month $ 6.70 per month
- For bills over 325 KWH per month $11.00 per month

Energy Charge

- Any part of the first 500 KWH per month — 6.70¢ net per KWH
- Over 500 KWH per month — 4.40¢ net per KWH
- With electric heating and/or water heating over 1000 KWH per month — 3.18¢ net per KWH

Examples of Block Rates

Residential Rate* (PSI)

Connection Charge..... $9.40

First 300 kWh..... $0.092945 per kWh

Next 700 kWh..... $0.054178 per kWh

Over 1000 kWh ..... $0.044464 per kWh

Monthly Minimum Charge

The minimum charge shall be the Connection Charge.

Examples of Rates

IPL Large Secondary Service RATE:
The Customer Charge; plus the sum of the Demand Charge and the Energy Charge adjusted according to the "Power Factor" clause.

Customer Charge	$103.33

Demand Charge

- First 500 KW of billing demand per month @ $10.55 net per KW
- Over 500 KW of billing demand per month @ $10.18 net per KW

Energy Charge	2.68¢ net per KWH

Examples of Rates

IPL High Load Factor Rate

Customer Charge $310.67

Demand Charge

- For service at primary distribution voltage (4160 or 13,200 volts)
- First 4000 KW of billing demand per month @ $11.11 net per KW
- Over 4000 KW of billing demand per month @ $10.57 net per KW
- For service at sub-transmission voltage (34,500 volts)
- First 4000 KW of billing demand per month @ $10.95 net per KW
- Over 4000 KW of billing demand per month @ $10.60 net per KW
- For service at transmission voltage (138,000 or 345,000 volts)
- First 4000 KW of billing demand per month @ $10.65 net per KW
- Over 4000 KW of billing demand per month @ $ 9.90 net per KW

Energy Charge

- For service at primary distribution voltage 2.07¢ net per KWH
- For service at sub-transmission voltage 1.99¢ net per KWH
- For service at transmission voltage 1.99¢ net per KWH

Time-of-Use Pricing

The pricing of electricity based on the estimated cost of electricity during a particular time block.

Time-of-use rates are usually divided into two or three time blocks per twenty four hour period – and can be seasonally adjusted.

In a time-of-use structure, higher prices are charged during utility peak load times – the set of prices are fixed in the tariff.

Such rates can provide an incentive for consumers to curb power use during peak times.

Real-Time Pricing vs. TOU Pricing

Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many time a day and are weather-sensitive, rather than varying with a fixed schedule.

Real-time pricing is most applicable to utilities that purchase a significant portion of their power from wholesale spot markets

Utilities that generate their own power – particularly those that operate under a fuel adjustment clause – have little to gain from real-time pricing.

Interruptible Rates

Unbundled rate elements can serve as a useful guide for the determination of Interruptible Rates.

Interruptible Rates are discounted rates offered to customers who agree to have their service (or at least a portion of their service) interrupted.

Maximum Discount = Demand related charges - determined on a case-by-case basis.

Interruptible Rates – cont.

- Less notice time to interrupt = bigger discount
- More maximum number of interruptions per year = bigger discount
- Longer maximum duration per interruption = bigger discount
- Interruption controlled by utility dispatch (rather than by the customer) = bigger discount
- Shorter minimum time between interruption = bigger discount
- Need to establish penalties for non-compliance.