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Methodology of Cost Allocation

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Purpose of Cost Allocation

- Determine whether each class of customers is providing the utility with a reasonable level of revenue necessary to cover the investments and costs of providing service to that class.

- Determine class revenue requirement/responsibility of each class for its equitable share of the utility's total annual cost of providing service within a given jurisdiction.
  - Creates pricing signals that encourage efficient use of system capacity.
  - Avoids undue price discrimination among classes of customers.

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Cost Allocation

- Cost of Service study is an analysis of the total costs a utility incurs to provide service.
  - * Plant Investment – production, transmission, storage, distribution & general
  - * Expenses
    - - Operation and Maintenance
    - - Administrative and General
    - - Labor
    - - Taxes
- Class Cost of Service study is an analysis of the total costs incurred by a utility and allocated to various rate classes.

Cost Allocation (Cont'd)

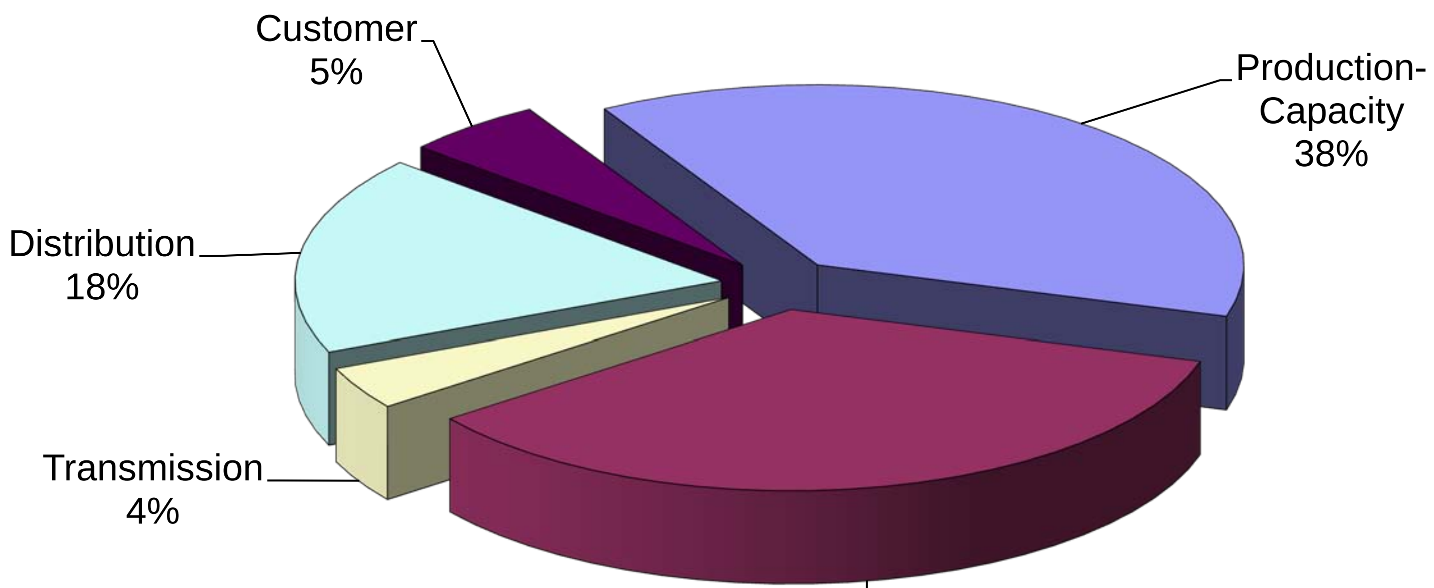
- Class Cost of Service Study will:
  - Step 1: Functionalize Costs
  - Step 2: Classify Cost
  - Step 3: Allocate Costs

- At each step ask, "What caused the cost to be incurred?"

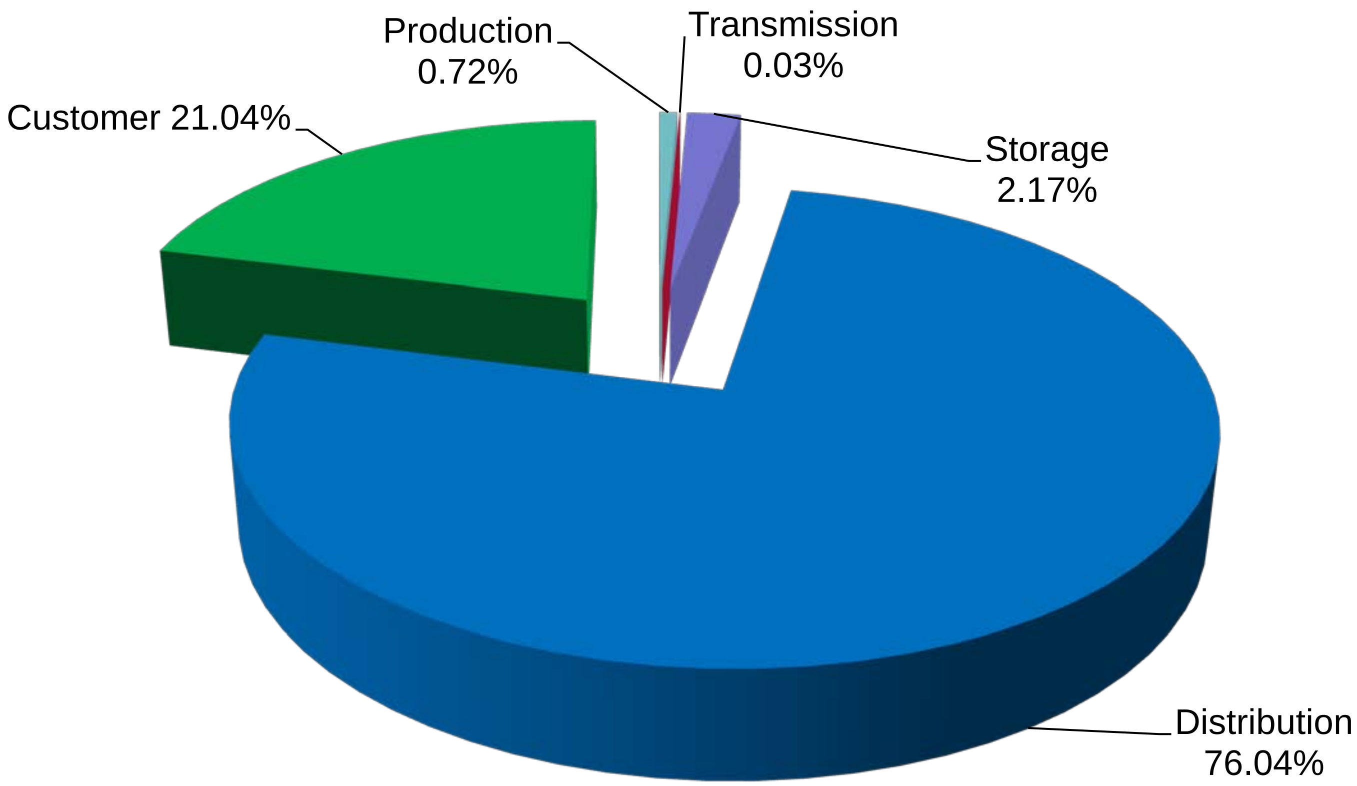
Functionalization

- The grouping of plant investment and operation expense accounts according to the specific function they play in the operations of the utility system.
  - Production
  - Storage (Natural Gas Only)
  - Transmission
  - Distribution
  - Customer
  - Administrative and General
    - Classified as production, transmission, distribution and customer.

Total Functionalized Costs of a Vertically Integrated Electric Utility



Total Functionalized Costs of a Natural Gas Utility

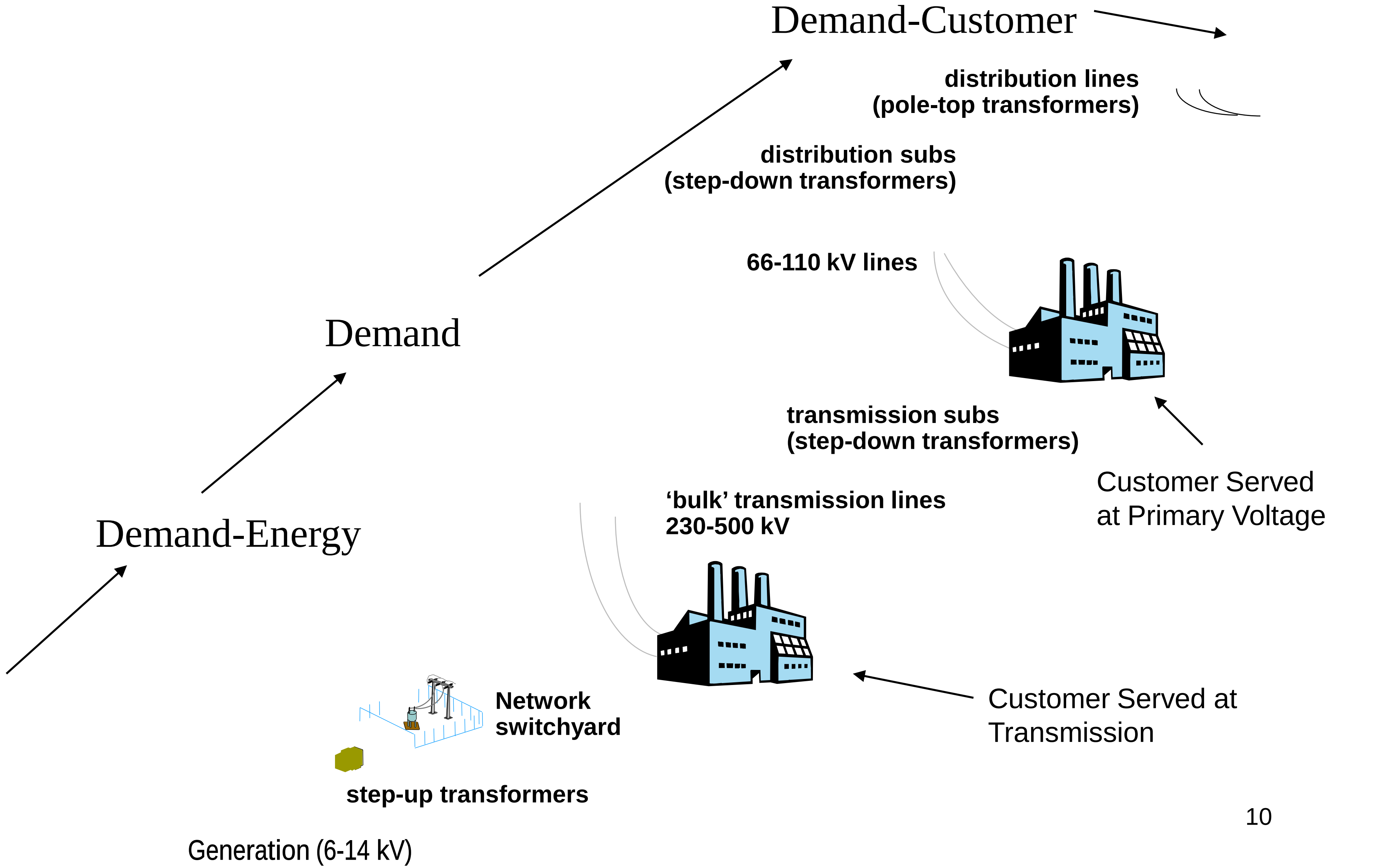


Classification

- Classification is a means to divide the functionalized, cost-defining components into:
  - Customer Related Costs
    - Costs that vary with the number of customers
  - Demand Related Costs
    - Costs that vary with kW of peak demand
  - Energy Related Costs
    - Costs that vary with kWh of energy

Allocation

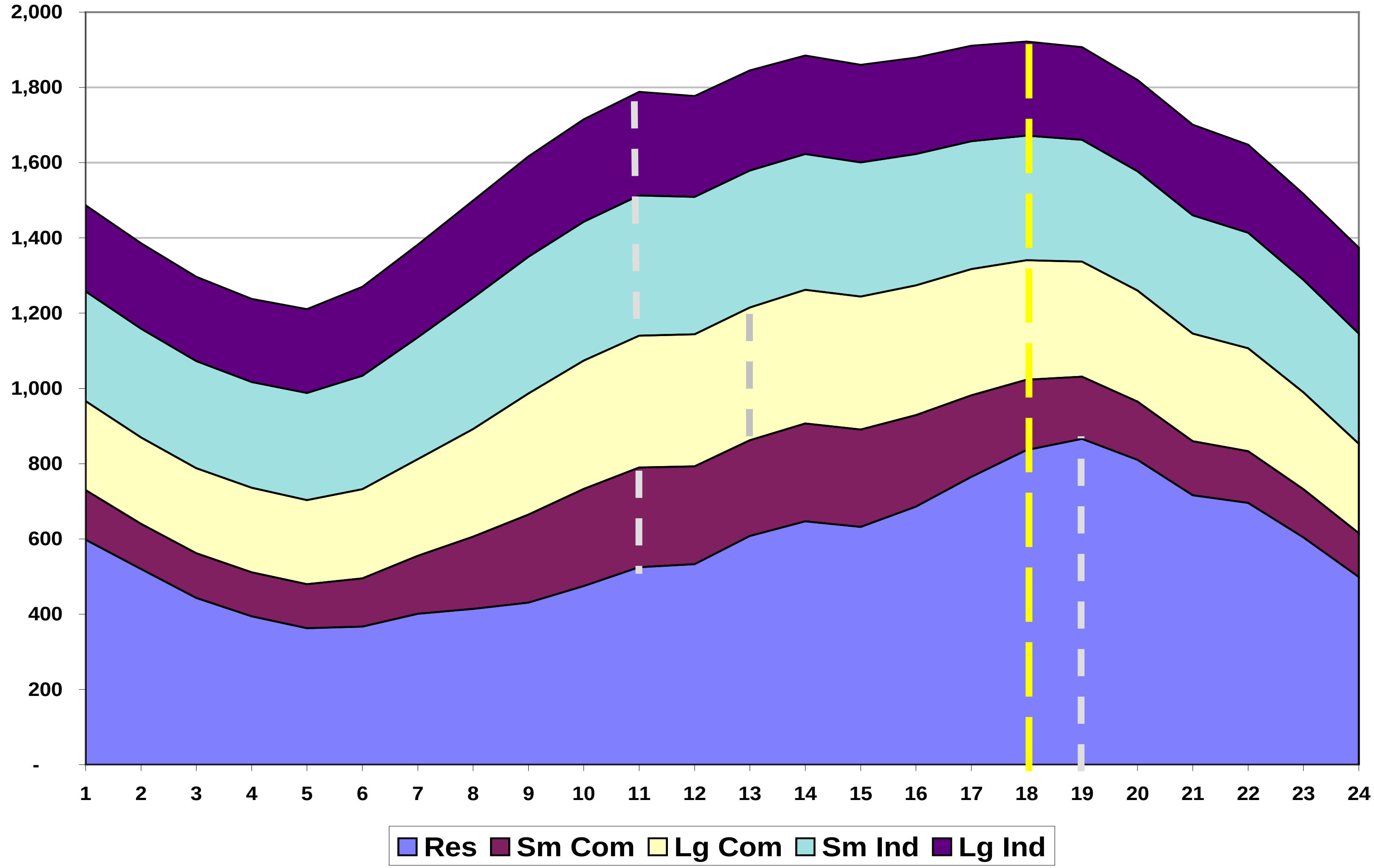
- The process of assigning costs to different customer classes.
  - Customer classes are based on similarities in usage levels, voltage levels at which the customer is served and other conditions of service, such as demand meters.
  - Customer Categories Include:
    - Industrial (Transmission, Substation, Primary and Secondary)
    - Commercial (Primary and Secondary)
    - Residential (Secondary)


Demand-Customer
distribution lines
(pole-top transformers)
distribution subs
(step-down transformers)
66-110 kV lines
Demand
transmission subs
(step-down transformers)
Customer Served
at Primary Voltage
'bulk' transmission lines
230-500 kV
Demand-Energy
Network
switchyard
Customer Served at
Transmission
step-up transformers
Generation (6-14 kV)

Foundation For Demand Allocators

- Average Demand – total kWh during a cycle divided by the number of hours in the cycle.
  - 8760 hours in a year
- Peak Demand – is the maximum hourly demand (load) during the cycle (measured in kW or MW).
  - Coincident Peak Load (CP) – a customer class's peak load at the time of total system peak.
  - Non-Coincident Peak Load (NCP) – a customer class's peak load regardless of when it happens.
    - Customer Maximum Demands (MDD) – sum of individual customer demands within a specific class.

System Load Diversity



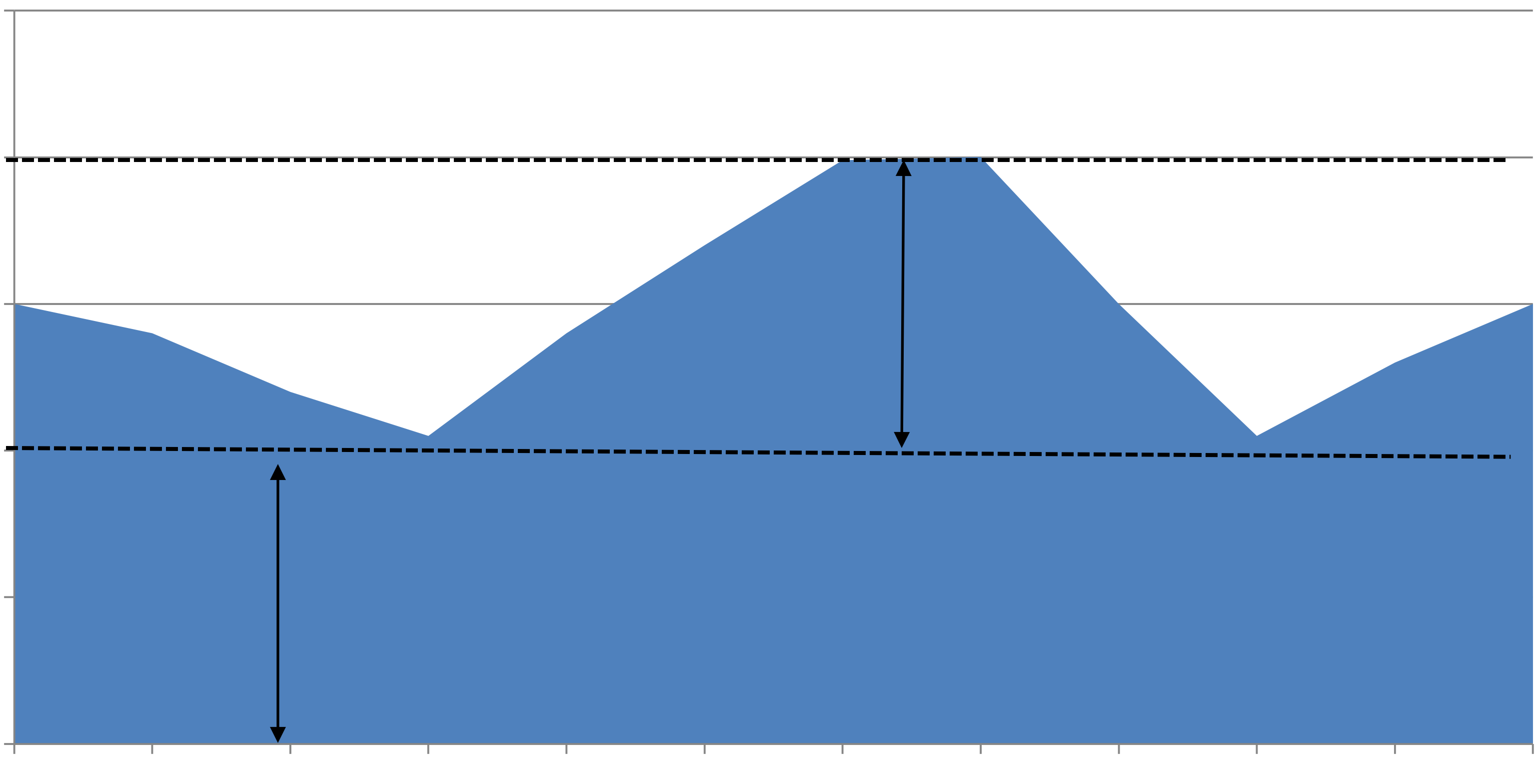
Natural Gas Conversions

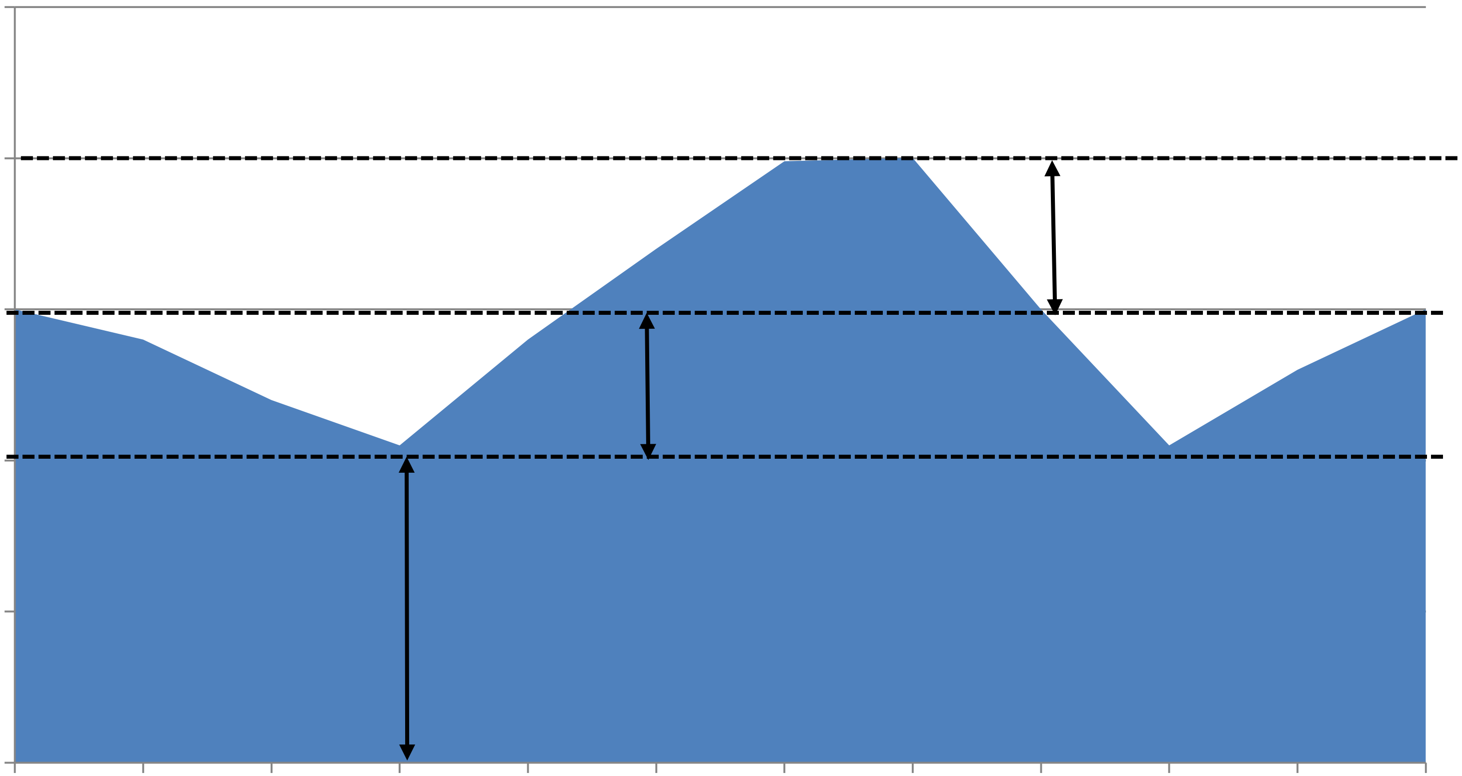
- 1 Cubic Meter = 35.31 Cubic Feet
- 100 cubic feet (1 ccf) • 2.83 m^3
- 1 Therm = 100,000 Btu • 1 ccf
- 1 Million British Thermal Units (MMBtu) = 10 Therms

Methods of Allocation

Demand-Related Cost Allocation Methods

- Coincident Peak Demand (1CP, 4CP, 12CP)
- Non Coincident Peak Demand (1NCP, 4NCP, 12NCP)
  - Customer Maximum Demands (MDD)
- Average-Excess Demand
  - This method uses a weighted average of the average-demand allocators (weight = system load factor) and the Excess-Demand Allocators (weight = one minus the system load factor).
- Base, Intermediate and Peak (BIP) (Missouri's Method)
  - The base portion of this method is a weighted average of the average demand allocator (weight = system load factor) and the intermediate and peak portions are a weighted average of the average peak demand allocators (weight = one minus the system load factor).





Methods of Allocation (Cont'd)

– Energy-Related Cost Allocation Methods

- kWh of Energy Sold or Volumes of Gas Sold
  - kWh at Meter and at Generator
- Compared to high voltage customers, low voltage customers have higher loss factors because: (1) they are further "downstream" from the generation sources and (2) line losses are inversely related to line voltage levels.

– Customer-Related Cost Allocation Methods

- Number of Customer
- Weighted Number of Customers – weights can be based on:
  - Average meter costs
  - Average billing costs
  - Average meter-reading costs

Methods of Allocation (Cont'd)

Customer and Demand-Related Allocation

Ex. Distribution Plant Investment in Mains

Customer Component

- Typical cost of main per customer multiplied by the number of customers in the class
  - Length of main directly associated with a typical customer in each class
  - The diameter of the main that would be required to serve that customer

Demand Component

- Estimated peak day demands of each class

Data Requirements To Develop Allocators

Electric Utility Provides:

- Hourly load information per customer class based on load research studies
  - Diversity Factors
- Line Loss Study
- Number of customers served in each customer class at each voltage level
- Monthly usage (kWh) and demand (kW) information for each customer class
  - Number of days per bill cycle
- Customer related cost data
  - Meter and Billing costs

Data Requirements (Cont'd)

Natural Gas Utility Provides:

- Volumes of gas sold and transported by customer class and by bill cycle
  - Meter Read Dates or number of days per bill cycle
- Average length and cost of service main for each class of customers
  - Usually based on a sample of customers
- Customer related costs
  - Customer Service costs
  - Meter costs & House Regulator costs per class of customers

Sample of Data Output

RESIDENTIAL

NCP				

RESIDENTIAL

CP				

Demand loss rates	1.0186	1.0237	1.0068	1.0287

Allocator Usage

- Using the methods of allocation and the data received from the utility, we assign specific allocators to specific functions.

- A general principal to follow is:
  - For example, production maintenance expenses are allocated using the same methodology as production plant. Same relationship exists for transmission, storage and distribution expenses.

Results of Class Cost of Service

- Total cost to serve a class = Expenses + Return on Investment

Functional Category	Residential	Commercial Primary	Commercial Secondary	Industrial Primary	Industrial Secondary	Industrial Substation	Industrial Trans.	Total
Production – Demand	$128,140,056	$440,413	$38,233,710	$31,571,581	$12,553,553	$10,868,441	$6,685,527	$227,973,813
Production - Energy	$40,651,586	$260,498	$19,500,782	$23,129,285	$8,855,237	$8,128,200	$4,680,467	$104,686,585
Transmission	$9,532,613	$47,252	$3,577,149	$3,344,128	$1,280,761	$1,174,899	$677,307	$19,114,641
Distribution - Substations	$4,706,569	$17,185	$1,190,944	$1,021,363	$396,497	$346,264	$0	$7,159,353
Distribution - Primary	$17,272,306	$68,760	$4,765,036	$4,086,533	$1,586,408	$0	$0	$27,259,575
Distribution - Secondary	$19,234,824	$0	$4,829,300	$0	$1,229,538	$0	$0	$24,774,193
Customer	$30,513,005	$35,199	$2,414,789	$38,870	$10,636	$5,366	$7,155	$32,505,551
Total	**$250,050,959**	**$869,307**	**$74,511,710**	**$63,191,760**	**$25,912,630**	**$20,523,170**	**$12,050,456**	**$443,473,710**

Seasonal Differentiated Tariffs

- For most electric utilities in Missouri the summer months include June, July, August and September. The remaining eight months are considered winter months.
- For most gas utilities in Missouri the winter months are November, December, January, February and March and the remaining seven months are considered summer months. One gas utility is split evenly with six winter months and six summer months.
- Many Missouri electric utilities peak in the summer, therefore summer rates tend to be higher.
- All gas utilities in Missouri peak in the winter, therefore rates in the winter tend to be higher.

Using Class Cost of Service To Determine Seasonal Rates

Cost Category	Residential Annual	Residential Winter	Residential Summer
Production - Demand	$129,503,853	$65,562,446	$63,941,407
Production - Energy	$40,724,337	$23,528,727	$17,195,610
Transmission	$9,146,149	$4,880,785	$4,265,364
Distribution - Substations	$4,248,888	$2,031,530	$2,217,358
Distribution - Primary	$17,000,055	$8,128,274	$8,871,781
Distribution - Secondary	$18,991,533	$9,049,533	$9,942,000
Customer	$30,436,143	$20,290,762	$10,145,381
Total Costs to be Recovered in Rates	**$250,050,959**	**$133,472,059**	**$116,578,900**
# of Customers	189,263		
kWh @ Meter	1,904,348,334	1,086,293,179	818,055,155
Monthly Customer Charge	$13.40		
Energy Costs	$0.0214	$0.0217	$0.0210
Demand Costs ($/kWh)	$0.0939	$0.0825	$0.1091

Time of Use Tariff

- Time-of-use rates or time-of-day rates, are rates that change based on the time the energy is used.
  - In a 24-hour day the hours are designated as “On-peak” or “Off-peak” and sometimes a third option of “Shoulder”. A different rate applies to energy used at the designated times.
    - Provides an incentive to move energy usage from peak to off-peak hours.
    - Can be used for all classes of customers.
      - Especially for industrial customers
    - Hourly load research data is needed to determine hours of peak and off-peak usage and the level of usage within those hours.

Sample Industrial Customer Tariff Sheet

BILLING PERIODS

Weekdays	**Summer**	**Winter**
Peak	10:00 - 22:00	7:00 - 22:00
Off-Peak	22:00 - 10:00	22:00 - 7:00
Weekends		
Off-Peak	All hours	All hours

MONTHLY RATE (Secondary, Primary, Substation and Transmission)

	Summer	**Winter**
Customer Charge		
First 500 kW	$1140.56	$1140.56
Over 500 kW	$1.81 per kW	$1.81 per kW
Energy Charge		
Peak	$0.0607 per kWh	$0.0501 per kWh
Off-Peak	$0.0427 per kWh	$0.0377 per kWh
Billed Demand Charge		
For each kW	$13.12 per kW	$5.60 per kW

Sample Large Customer Tariff Sheet (Cont'd)

- Metering Loss Adjustment
  - Service Metered at Primary Voltage – Where service is provided directly from a twelve (12) kV circuit feeder and is metered at four (4) kV or twelve (12) kV, the metered kWh and kW will be reduced by one and one-half percent (1.5%).
  - Service Metered at Substation Voltage – Where service is metered at four (4) kV or twelve (12) kV directly from a substation the metered kWh and kW will be reduced by two and one-half percent (2.5%).
  - Service Metered at Transmission Voltage – Where service is metered at thirty-four (34) kV and above directly from a transmission line, the metered kWh and kW will be reduced by three percent (3%).

- If there is no metering loss adjustment, there would be a separate tariff for each voltage level.

Sample Residential Tariff Sheet

BILLING PERIODS

Weekdays	**Summer**	**Winter**
Peak	13:00 - 20:00	7:00 - 22:00
Shoulder	6:00 - 13:00	
Shoulder	20:00 - 22:00	
Off-Peak	22:00 - 6:00	22:00 - 7:00

Weekends		
Shoulder	6:00 - 22:00	
Off-Peak	22:00 - 6:00	All hours

MONTHLY RATE

	Summer	**Winter**
Customer Charge	$18.46 per month	$18.46 per month
Energy Charge		
Peak	$0.2036 per kWh	$0.1307 per kWh
Shoulder	$0.1131 per kWh	
Off-Peak	$0.0679 per kWh	$0.0522 per kWh

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Questions?

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