# ELECTRIC UTILITY
# COST ALLOCATION MANUAL

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NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

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# CONTENTS

# CHAPTER 4

## EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

### I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

## II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

### FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS

| | Cost Classes | | | |
|---|---|---|---|---|
| **Functions** | **Demand** | **Energy** | **Customer** | **Revenue** |
| Production | | | | |
| Thermal | X | X | N/A | N/A |
| Hydro | X | X | N/A | N/A |
| Other | X | X | N/A | N/A |
| Transmission | X | X | X | N/A |
| Distribution | X | X | X | N/A |
| OH/UG Lines | X | X | X | N/A |
| Substations | X | X | X | N/A |
| Services | N/A | N/A | X | N/A |
| Meters | N/A | N/A | X | N/A |
| Customer | N/A | N/A | X | X |

# III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

## A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

| FERC Uniform System of Accounts No. | Description | Demand Related | Customer Related |
|---|---|---|---|
| **CLASSIFICATION OF RATE BASE[1]** | | | |
| **Production Plant** | | | |
| 301-303 | Intangible Plant | x | - |
| 310-316 | Steam Production | x | x |
| 320-325 | Nuclear Production | x | - |
| 330-336 | Hydraulic Production | x | x[2] |
| 340-346 | Other Production | x | - |

**Exhibit 4-1**
**(Continued)**

CLASSIFICATION OF PRODUCTION PLANT

| FERC Uniform System of Accounts No. | Description | Demand Related | Energy Related |
|---|---|---|---|

**CLASSIFICATION OF EXPENSES[1]**

**Production Plant**

**Steam Power Generation Operations**

| | | | |
|---|---|---|---|
| 500 | Operating Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 501 | Fuel | - | x |
| 502 | Steam Expenses | x[4] | x[4] |
| 503-504 | Steam From Other Sources & Transfer. Cr. | - | x |
| 505 | Electric Expenses | x[4] | x[4] |
| 506 | Miscellaneous Steam Pwr Expenses | x | - |
| 507 | Rents | x | - |

**Maintenance**

| | | | |
|---|---|---|---|
| 510 | Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 511 | Structures | x | - |
| 512 | Boiler Plant | - | x |
| 513 | Electric Plant | - | x |
| 514 | Miscellaneous Steam Plant | - | x |

**Nuclear Power Generation Operation**

| | | | |
|---|---|---|---|
| 517 | Operation Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 518 | Fuel | - | x |
| 519 | Coolants and Water | x[4] | x[4] |
| 520 | Steam Expense | x[4] | x[4] |
| 521-522 | Steam From Other Sources & Transfe. Cr. | - | x |
| 523 | Electric Expenses | x[4] | x[4] |
| 524 | Miscellaneous Nuclear Power Expenses | x | - |
| 525 | Rents | x | - |

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

| FERC Uniform System of Accounts No. | Description | Demand Related | Energy Related |
|---|---|---|---|
| | **Maintencance** | | |
| 528 | Supervision & Engineering | Prorated on Labor[3] | Prorated on Labor[3] |
| 529 | Structures | x | - |
| 530 | Reactor Plant Equipment | - | x |
| 531 | Electric Plant | - | x |
| 532 | Miscellaneous Nuclear Plant | - | x |
| | **Hydraulic Power Generation Operation** | | |
| 535 | Operation Supervision and Engineering | Prorated on Labor[3] | Prorated on Labor[3] |
| 536 | Water for Power | x | - |
| 537 | Hydraulic Expenses | x | - |
| 538 | Electric Expense | x[4] | x[4] |
| 539 | Misc Hydraulic Power Expenses | x | - |
| 540 | Rents | x | - |
| | **Maintenance** | | |
| 541 | Supervision & Engineering | Prorated On Labor[3] | Prorated On Labor[3] |
| 542 | Structures | x | - |
| 543 | Reservoirs, Dams, and Waterways | x | x |
| 544 | Electric Plant | x | x |
| 545 | Miscellaneous Hydraulic Plant | x | x |

**Exhibit 4-1**
**(Continued)**

| FERC Uniform System of Account | Description | Demand Related | Energy Related |
|---|---|---|---|
| | **CLASSIFICATION OF EXPENSES**[1] | | |
| | **Other Power Generation Operation** | | |
| 546, 548-554 | All Accounts | x | - |
| 547 | Fuel | - | x |
| | **Other Power Supply Expenses** | | |
| 555 | Purchased Power | x[5] | x[5] |
| 556 | System Control & Load Dispatch | x | - |
| 557 | Other Expenses | x | - |

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that 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.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

## B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

## IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

## 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 |

Peak demand methods include the single coincident peak method, the summer and winter peak method, the twelve monthly coincident peak method, multiple coincident peak method, and an all peak hours approach. Energy weighting methods include the average and excess method, equivalent peaker method, the base and peak method, and methods using judgmentally determined energy weightings, such as the peak and average method and variants thereof.

## A. Peak Demand Methods

Cost of service methods that utilize a peak demand approach are characterized by two features: First, all production plant costs are classified as demand-related. Second, these costs are allocated among the rate classes on factors that measure the class contribution to system peak. A customer or class of customers contributes to the system maximum peak to the extent that it is imposing demand at the time of -- coincident with -- the system peak. The customer's demand at the time of the system peak is that customer's "coincident" peak. The variations in the methods are generally around the number of system peak hours analyzed, which inturn depends on the utility's annual load shape and on system planning considerations.

Peak demand methods do not allocate production plant costs to classes whose usage occurs outside peak hours, to interruptible (curtailable) customers.

## 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.

## 1. Single Coincident Peak Method (1-CP)

**O***bjective:* The objective of the single coincident peak method is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load.

***Data Requirements:*** The 1-CP method uses recorded and/or estimated monthly class peak demands. In a large system, this may require complex statistical sampling and data manipulation. A competent load research effort is a valuable asset.

***Implementation:*** Table 4-1 contains illustrative load data for five customer classes for 12 months of a test year. The analyst simply translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements; that is, to the revenue requirements that are functionalized to production and classified to demand. This operation is shown in Table 4-5.

**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 |

## 2. Summer and Winter Peak Method

*Objective:* The objective of the summer and winter peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. If the summer and winter peaks are close in value, and if both significantly affect the utility's generation expansion planning, this approach may be appropriate.

*Implementation:* The number of summer and winter peak hours may be determined judgmentally or by applying specified criteria. One method is simply to average the class contributions to the summer peak hour demand and the winter peak hour demand. Another method is to choose those summer and winter hours where the peak demand or reliability index passes a specified threshold value. Clearly, the selection of the hours is critical and the establishment of selection criteria is particularly important. These cost of service judgements must be made jointly with system planners and supported with good data. The analyst should review FERC cases, where this issue often comes up. Table 4-6 shows the allocators and resulting allocations of production plant revenue responsibility for the example using the three highest summer and three highest winter coincident peak demand hours.

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 |

## 3. The Sum of the Twelve Monthly Coincident Peak (12 CP) Method

*Objective:* This method uses an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky. The 12-CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs or other reliability index values in all months.

*Data Requirements:* Reliable monthly load research data for each class of customers and for the total system is the minimum data requirement. The data can be recorded and/or estimated.

*Implementation:* Table 4-7 shows the derivation of the 12 CP allocator and the resulting allocation of production plant costs for the example case.

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 Generation (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 | 2,932 | 26.71 | 283,283,130 |
| AG&P | 266 | 2.42 | 25,700,311 |
| SL | 38 | 0.35 | 3,671,473 |
| TOTAL | 10,976 | 100.00 | $ 1,060,476,000 |

## 4. Multiple Coincident Peak Method

This section discusses the general approach of using the classes' demands in a certain number of hours to derive the allocation factors for production plant costs. The number of hours may be determined judgmentally; e.g., the 10 or 20 hours in the year with the highest system demands, or by applying specified criteria. Criteria for determining which hours to use include: (1) all hours of the year with demands within 5 percent or 10 percent of the system's peak demand, and (2) all hours of the year in which a specified reliability index (loss of load probability, loss of load hours, expected unserved energy, or reserve margin) passes an established threshold value. This may result in a fairly large number of hours being included in the development of the demand allocator.

## 5. All Peak Hours Approach

This method resembles the multiple CP approach except it bases the allocation of demand-related production plant costs on the classes' contributions to all defined, rather than certain specified, on-peak hours. This method requires scrutiny of all hours of the year to determine which are most likely to contribute to the need for the utility to add production plant. If the on-peak rating periods -- i.e., the hours or periods in which on-peak rates apply -- are properly defined, then all hours in the on-peak period are critical from the utility's planning perspective. Table 4-8 shows the allocators and resulting cost allocation based on the classes' shares of on-peak KWH for the example utility. For the example utility, the on-peak periods are from 5:00 p.m. to 9:00 p.m. on winter weekdays and from 12:00 noon to 6:00 p.m. on summer weekdays.

The on-peak hours may be defined using various criteria, such as those hours with a preponderance of actual peak demands, those with the majority of annual loss of load probabilities, loss of load hours or those in which other reliability indexes register critical values. Using this method requires satisfactory load research and computer capability to estimate the classes' loads in the defined on-peak periods.

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.

## 6. Summary: Peak Demand Responsibility Methods

Table 4-9 is a summary of the allocation factors and revenue allocations for the methods described above. The most important observations to be drawn from this information are:

- The number of hours chosen as the basis for the demand allocator can have a significant effect on the revenue allocation, even for relatively small numbers of hours.
- The greater the number of hours used, the more the allocation will reflect energy requirements. If all 8,760 hours of a year were used, the demand and a KWH (energy) allocation factors would be the same.

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.

## B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

### 1. Average and Excess Method

*Objective:* The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

*Data Requirements:* The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

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.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

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.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

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

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

| Rate Class | Energy Allocation Factor - Average MW | Energy Allocatn. Factor (%) | Energy-Related Production Plant Revenue Requirement | Excess Demand Allocation Factor (NCP MW - Avg. MW) | Excess Demand Alloctn. Factor (Percent) | Demand-Related Production Plant Revenue Requirement | Class Production Plant Revenue Requiremnt |
|---|---|---|---|---|---|---|---|
| DOM | 2,440 | 30.96 | 190,387,863 | 2,917 | 44.05 | 196,294,822 | 386,682,685 |
| LSMP | 2,669 | 33.87 | 208,256,232 | 2,393 | 36.14 | 161,033,085 | 369,289,317 |
| LP | 2,459 | 31.21 | 191,870,391 | 926 | 13.98 | 62,313,680 | 254,184,071 |
| AG&P | 254 | 3.22 | 19,819,064 | 318 | 4.80 | 21,399,298 | 41,218,363 |
| SL | 58 | 0.74 | 4,525,613 | 68 | 1.03 | 4,575,951 | 9,101,564 |
| TOTAL | 7,880 | 100.00 | 614,859,163 | 6,622 | 100.00 | 445,616,837 | 1,060,476,000 |

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

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

## 2. Equivalent Peaker Methods

*Objective:* Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

***Data Requirements:*** This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

### *A Digression on System Planning with Reference to Plant Cost Allocation:*

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

### *Classification of Generation:*

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

A variant of the above approach is to do the equivalent peaker cost evaluations based only on the viable generation alternatives available to the utility at any point in time. For example, combined cycle technology might be so much more cost-effective than the next best option that it would be the preferred choice for demand lasting as little as 50 to 100 hours. If so, then using a combustion turbine as the equivalent peaker "benchmark" might be inappropriate. Such choices would require careful analysis of alternate generation expansion paths on a case by case basis.

Consider the example shown in Table 4-11. The example utility has three 100 MW combustion turbines of varying ages. All investment in these units is classified as demand-related. The utility also has three unscrubbed coal-fired units of varying ages. The production plant costs of these units are classified as follows: first, the ratio of the cost of a new CT ($300/KW) to the cost of a new unscrubbed coal unit ($1000/KW) is calculated and found to be 30 percent. Then, this factor is multiplied by the rate base for each plant, and the result is classified as demand-related, with the remainder classified as energy-related. The cost of the utility's new, scrubbed coal unit is classified by the same method. Since the unit cost is $1200/KW, only 25 percent of it ($300/KW)/($1200/KW) is classified as demand-related, with the remaining three-fourths classified as energy-related. Treating the utility's nuclear unit similarly, only 15 percent of its cost ($300/KW)/($2000/KW) is classified as demand-related.

TABLE 4-11
ILLUSTRATION OF DEMAND AND ENERGY AND ENERGY CLASSIFICATION OF GENERATING UNITS USING THE EQUIVALENT PEAKER METHOD

| Unit | Unit Type | Capacity (MW) | Rate Base | Percent Class Demand-Related | Demand-Related Rate Base | Energy-Related Rate Base |
|---|---|---|---|---|---|---|
| A | CT | 100 | 10,000,000 | 100 | 10,000,000 | 0 |
| B | CT | 100 | 20,000,000 | 100 | 20,000,000 | 0 |
| C | CT | 100 | 30,000,000 | 100 | 30,000,000 | 0 |
| D | Coal | 200 | 80,000,000 | 30 | 24,000,000 | 56,000,000 |
| E | Coal | 250 | 100,000,000 | 30 | 30,000,000 | 70,000,000 |
| F | Coal | 450 | 270,000,000 | 30 | 81,000,000 | 189,000,000 |
| G | Coal W/FDG | 600 | 720,000,000 | 25 | 180,000,000 | 540,000,000 |
| H | Nuclear | 900 | 1,800,000,000 | 15 | 270,000,000 | 1,530,000,000 |
| TOTAL | | 2,700 | $ 3,030,000,000 | 21 | $ 645,000,000 | $ 2,385,000,000 |

The equivalent peaker classification method applied in the example above ignores the fuel savings that accrue from running a base unit rather than a peaker. Discussions with planners can help incorporate the effects of fuel savings into the classification.

Table 4-12 shows the revenue responsibility for the rate classes using the equivalent peaker cost method applied to the example utility's data. In this example, a summer and winter peak demand allocator was used to allocate the demand-related costs. Observe that the total revenue requirement allocation among the rate classes is significantly different from that resulting from any of the pure peak demand responsibility methods.

TABLE 4-12

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE EQUIVALENT PEAKER COST METHOD

| Rate Class | Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%) | Demand-Related Production Plant Revenue Requirement | Energy Allocation Factor (Total MWH) | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requiremnt |
|---|---|---|---|---|---|
| DOM | 36.67 | 78,980,827 | 30.96 | 261,678,643 | 340,659,471 |
| LSMP | 35.50 | 76,460,850 | 33.87 | 286,237,828 | 362,698,678 |
| LP | 25.14 | 54,147,205 | 31.21 | 263,716,305 | 317,863,510 |
| AG&P | 2.22 | 4,781,495 | 3.22 | 27,240,318 | 32,021,813 |
| SL | 0.47 | 1,012,299 | 0.74 | 6,220,230 | 7,232,529 |
| TOTAL | 100.00 | 215,382,676 | 100.00 | 845,093,324 | $1,060,476,000 |

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

### 3. Base and Peak Method

*Objective:* The objective of the base and peak method is to reflect in cost allocation the argument that an on-peak kilowatt-hour costs more than an off-peak kilowatt-hour and that the extra cost should be borne by the customers imposing it. This approach first identifies the same production plant cost components as the equivalent peaker cost method, and allocates demand-related production plant costs in the same way. The difference is that, using the base and peak method, the energy-related excess capital costs are allocated on the basis of the classes' proportions of <u>on-peak</u> energy use instead of being allocated according to the classes' shares of <u>total</u> system energy use. The logic of this approach is that the extra capital costs would be incurred once the system was expected to run for a certain minimum number of hours; i.e., once the break-even point in unit run time between a peaker and a baseload (or intermediate) unit was reached. However, system planners generally recognize no difference between on-peak hours and off-peak energy loads on the decision to build a baseload power plant, instead, the belief is that system planners consider the total annual energy loads that determine the type of plant to build. To allocate energy-related production plant costs on the basis of only on-peak energy use implies a differential impact of on-peak KWH as compared to off-peak KWH that may or may not exist.

Table 4-13 shows the results of a base and peak cost of service method for the example utility.

TABLE 4-13

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

| Rate Class | Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%) | Demand-Related Production Plant Revenue Requirement | Energy Allocation Factor On-Peak MWH | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 36.67 | 78,980,827 | 32.13 | 271,541,532 | 350,522,360 |
| LSMP | 35.50 | 76,460,850 | 36.21 | 306,044,166 | 382,505,016 |
| LP | 25.14 | 54,147,205 | 28.26 | 238,860,669 | 293,007,874 |
| AG&P | 2.22 | 4,781,495 | 2.73 | 23,086,785 | 27,868,280 |
| SL | 0.47 | 1,012,299 | 0.66 | 5,560,171 | 6,572,470 |
| TOTAL | 100.00 | 215,382,676 | 100.00 | 845,093,324 | $1,060,476,000 |

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

## 4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

| Rate Class | Demand Allocation Factor - 1 CP MW (Percent) | Demand-Related Production Plant Revenue Requirement | Avg. Demand (Total MWH) Allocation Factor | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 34.84 | 233,869,251 | 30.96 | 120,512,062 | 354,381,313 |
| LSMP | 37.25 | 250,020,306 | 33.87 | 131,822,415 | 381,842,722 |
| LP | 24.63 | 165,313,703 | 31.21 | 121,450,476 | 286,764,179 |
| AG&P | 3.29 | 22,078,048 | 3.22 | 12,545,108 | 34,623,156 |
| SL | 0.00 | 0 | 0.74 | 2,864,631 | 2,864,631 |
| TOTAL | 100.00 | 671,281,308 | 100.00 | 389,194,692 | $1,060,476,000 |

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

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

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

| Rate Class | Demand Allocation Factor - 12 CP MW (Percent) | Demand-Related Production Plant Revenue | Average Demand (Total MWH) Allocation Factor | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 32.09 | 198,081,400 | 30.96 | 137,226,133 | 335,307,533 |
| LSMP | 38.43 | 237,225,254 | 33.87 | 150,105,143 | 387,330,397 |
| LP | 26.71 | 164,899,110 | 31.21 | 138,294,697 | 303,193,807 |
| AG&P | 2.42 | 14,960,151 | 3.22 | 14,285,015 | 29,245,167 |
| SL | 0.35 | 2,137,164 | 0.74 | 3,261,933 | 5,399,097 |
| TOTAL | 100.00 | 617,303,080 | 100.00 | 443,172,920 | $1,060,476,000 |

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

| Rate | Demand Allocation Factor - 12 CP MW (Percent) | Demand-Related Production Plant Revenue Requirement | Average Demand (Total MWH) Allocation Factor | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 32.09 | 314,111,612 | 30.96 | 25,259,288 | 339,370,900 |
| LSMP | 38.43 | 376,184,775 | 33.87 | 27,629,934 | 403,814,709 |
| LP | 26.71 | 261,492,120 | 31.21 | 25,455,979 | 286,948,099 |
| AG&P | 2.42 | 23,723,364 | 3.22 | 2,629,450 | 26,352,815 |
| SL | 0.35 | 3,389,052 | 0.74 | 600,426 | 3,989,478 |
| TOTAL | 100.00 | 978,900,923 | 100.00 | 81,575,077 | $1,060,476,000 |

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

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

## C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

### 1. Production Stacking Methods

*Objective:* The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

*Implementation:* In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

## 2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

| Rate Class | Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%) | Demand-Related Production Plant Revenue Requirement | Energy Allocation Factor (Total MWH) | Energy-Related Production Plant Revenue Requirement | Total Class Production Plant Revenue Requirement |
|---|---|---|---|---|---|
| DOM | 36.67 | 39,976,509 | 30.96 | 294,614,229 | 334,590,738 |
| LSMP | 35.50 | 38,701,011 | 33.87 | 322,264,499 | 360,965,510 |
| LP | 25.14 | 27,406,857 | 31.21 | 296,908,356 | 324,315,213 |
| AG&P | 2.22 | 2,420,176 | 3.22 | 30,668,858 | 33,089,034 |
| SL | 0.47 | 512,380 | 0.74 | 7,003,125 | 7,515,505 |
| TOTAL | 100.00 | 109,016,933 | 100.00 | 951,459,067 | $1,060,476,000 |

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

### 3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

### 4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT
COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

| | 1 CP METHOD | | 12 CP METHOD | | 3 SUMMER & 3 WINTER PEAK METHOD | | ALL PEAK HOURS APPROACH | | AVERAGE AND EXCESS METHOD | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total |
| DOM | $ 369,461,692 | 34.84 | $ 340,287,579 | 32.09 | $ 388,925,712 | 36.67 | $ 340,747,311 | 32.13 | $ 386,682,685 | 36.46 |
| LSMP | 394,976,787 | 37.25 | 407,533,507 | 38.43 | 376,433,254 | 35.50 | 384,043,376 | 36.21 | 369,289,317 | 34.82 |
| LP | 261,159,089 | 24.63 | 283,283,130 | 26.71 | 266,582,600 | 25.14 | 299,737,319 | 28.26 | 254,184,071 | 23.97 |
| AG&P | 34,878,432 | 3.29 | 25,700,311 | 2.42 | 23,555,089 | 2.22 | 28,970,743 | 2.73 | 41,218,363 | 3.89 |
| SL | 0 | 0.00 | 3,671,473 | 0.35 | 4,978,544 | 0.47 | 6,977,251 | 0.66 | 9,101,564 | 0.86 |
| Total | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.0 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.0 | $1,060,476,000 | 100.0 |

| | EQUIVALENT PEAKER COST METHOD | | BASE AND PEAK METHOD | | 1 CP AND AVERAGE DEMAND METHOD | | 12 CP AND 1/13th AVERAGE DEMAND METHOD | | PRODUCTION STACKING METHOD | |
|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total | Revenue Req't. ($) | Percent of Total |
| DOM | $ 340,657,471 | 32.12 | $ 3350,522,360 | 33.05 | $ 354,381,313 | 33.42 | $ 339,370,900 | 32.00 | $ 334,590,738 | 31.55 |
| LSMP | 362,698,678 | 34.20 | 382,505,016 | 36.07 | 381,842,722 | 36.01 | 403,814,709 | 38.08 | 360,965,510 | 34.04 |
| LP | 317,863,510 | 29.97 | 293,007,874 | 27.63 | 286,764,179 | 27.04 | 286,948,099 | 27.06 | 324,315,213 | 30.58 |
| AG&P | 32,021,813 | 3.02 | 27,868,280 | 2.63 | 34,623,156 | 3.36 | 26,352,815 | 2.48 | 33,089,034 | 3.12 |
| SL | 7,232,529 | 0.68 | 6,572,470 | 0.62 | 2,864,631 | 0.27 | 3,989,478 | 0.38 | 7,515,505 | 0.71 |
| Total | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 | $1,060,476,000 | 100.00 |

### 5. Summary

Table 4-18 summarizes the percentage allocation factors and revenue allocations for the cost of service methodologies presented in this chapter. Important observations are: (1) that the proportions of production plant costs classified as demand-related and energy-related can have dramatic effects on the revenue allocation; and (2) the greater the proportion classified as energy-related, the greater is the revenue responsibility of high load factor classes and the less is the revenue responsibility of low-load factor classes.

## V. FUEL EXPENSE DATA

Fuel expense data can be obtained from the FERC Form 1. Aggregate fuel expense data by generation type is found in Accounts 501, 518, and 547. Annual fuel expense by fuel type for specified generating stations can be found on pages 402 and 411 of Form 1.

Fuel expense is almost always classified as energy-related. It is allocated using appropriate time-differentiated allocators; e.g., on-peak KWH and off-peak KWH, or non-time-differentiated energy allocators (total KWH) calculated by incorporating adjustments to reflect different line and transformation losses at different levels of the utility's transmission and distribution system. Depending on the cost of service method used, it may be necessary to directly assign fuel expense to classes that are directly assigned the cost responsibility for specific generating units. Table 4-19 shows the allocation of fuel expense, other operation and maintenance expenses and purchased power expenses for the example utility. Fuel and purchased power expenses were allocated according to the classes' energy use at the generator level. Other operation and maintenance expenses were allocated using demand and energy allocators and ratio methods.

## VI. OTHER OPERATIONS AND MAINTENANCE EXPENSES FOR PRODUCTION

Other production O&M costs may also be classified as demand-related or energy-related. Typically, any costs that vary directly with the amount of energy produced, such as purchased steam, variable water cost and water treatment chemical costs, are classified as energy-related and allocated using appropriate energy allocation factors. Such cost items would typically be booked in Accounts 502 through 505 for fossil power steam generation, Accounts 519 and 520 for nuclear power generation, and Accounts 548 and 550.1 for other generation (excluding hydroelectric).

TABLE 4-19
ALLOCATED GENERATION FUEL, OPERATION, AND MAINTENANCE EXPENSES
(Thousands of Dollars)

| EXPENSE CATEGORY | TOTAL COMPANY RETAIL | DOMESTIC | LIGHTING, SMALL AND MEDIUM POWER | LARGE POWER | AGRICULTURAL AND PUMPING | STREET LIGHTING |
|---|---|---|---|---|---|---|
| Total Fuel | $ 871,598 | $269,887 | $295,147 | $272,028 | $28,068 | $ 6,467 |
| Steam Generation Expenses | | | | | | |
| Operation Expenses | 53,740 | 17,246 | 20,652 | 14,355 | 1,301 | 186 |
| Maintenance Expenses | 176,117 | 54,632 | 60,037 | 54,574 | 5,601 | 1,272 |
| Total Steam Excl. Fuel | 229,857 | 71,879 | 80,688 | 68,929 | 6,902 | 1,459 |
| Nuclear Generation Expenses | | | | | | |
| Operation Expenses | 106,851 | 34,291 | 41,061 | 28,541 | 2,587 | 371 |
| Maintenance Expenses | 88,787 | 27,552 | 30,305 | 27,475 | 2,817 | 638 |
| Total Nuclear Excl. Fuel | 195,638 | 61,842 | 71,366 | 56,017 | 5,404 | 1,009 |
| Hydraulic Generation Expenses | | | | | | |
| Operation Expenses | 9,730 | 3,054 | 3,462 | 2,872 | 284 | 58 |
| Maintenance Expenses | 13,135 | 4,123 | 4,674 | 3,877 | 383 | 78 |
| Total Hydraulic Expenses | 22,865 | 7,177 | 8,136 | 6,749 | 667 | 136 |
| Other Generation Expenses | | | | | | |
| Operation Expenses | 20,461 | 6,563 | 7,953 | 5,358 | 516 | 70 |
| Maintenance Expenses | 10,371 | 3,327 | 4,020 | 2,729 | 259 | 36 |
| Total Other Excl. Fuel | 30,832 | 9,890 | 11,973 | 8,087 | 775 | 106 |
| Purchased Power | 1,275,663 | 395,005 | 431,975 | 398,138 | 41,080 | 9,466 |
| System Control & Dispatch | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | $2,626,453 | $815,680 | $899,285 | $809,948 | $82,896 | $18,643 |

Note: Some values may not add to indicated totals or sub-totals due to rounding.

Operations and maintenance costs that do not vary directly with energy output may be classified and allocated by different methods. If certain costs are specifically related to serving particular rate classes, they are directly assigned. Some accounts may be easily identified as being all demand-related or all energy-related; these may then be allocated using appropriate demand andenergy allocators. Other accounts contain both demand-related and energy-related components. One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related. Another common method is to classify each account according to its "predominant" -- i.e., demand-related or energy-related -- character. Certain supervision and engineering expenses can be classified on the basis of the prior classification of O&M accounts to which these overhead accounts are related. Although not standard practice, O&M expenses may also be classified and allocated as the generating plants at which they are incurred are allocated.

## VII. SUMMARY AND CONCLUSION

### A. Choosing a Production Cost Allocation Method

As we have seen in the catalog of cost allocation methods above, the analyst chooses a method after considering many complex factors: (1) the utility's generation system planning and operation; (2) the cost of serving load with new generation or purchased power; (3) the incidence of new load on an annual, monthly and hourly basis; (4) the availability of load and operations data; and (5) the rate design objectives.

### B. Data Needs and Sources

Most of the cost of service methods reviewed above require: (1) rate base data; (2) operations and maintenance expense data, depreciation expense data, and tax data; and (3) peak demand and energy consumption data for all rate classes. Some methods also require information from the utility's system planners regarding the operation of specific generating units and more general data such as generation mix, types of plants and the plant loading; for example, how often the units are operated, and whether they are run as baseload, intermediate or peaking units. Rate base, O&M, depreciation, tax and revenue data are generally available from the FERC Form 1 reports that follow the uniform system of accounts prescribed by FERC for utilities (18 CFR Chapter 1, Subchapter C, Part 101). See Chapter 3 for a complete discussion of revenue requirements. Load data may be gathered by the utility or borrowed from similar neighboring utilities if necessary. Data or information relating to specific generating units must be obtained from the utility's system planners and power-system operators.

## C. Class Load Data

Any cost of service method that allocates part or all of production plant costs using a peak demand allocator requires at least estimates of the classes' peak demands. These may be estimates of the classes' coincident peak (CP) or non-coincident class peak (NCP) demands.

For larger utilities, class load data is generally developed from statistical samples of customers with time-recording demand and energy meters. Utilities without a load research program can sometimes borrow load data from others. See Appendix A for a thorough discussion of development of data through load research studies.

Different cost of service methods have different data requirements. The requirements may be as simple as: (1) total energy usage, adjusted for different line and transformation losses to be comparable at the generation level; (2) the class coincident peak demands in the peak hour of the year; and (3) the class non-coincident peak demands for the year. Some methods require much more complex data, ranging from class CP demands in each of the 12 monthly peak hours to estimated class demands in each hour of the year. Thus, load data development and analysis for cost of service studies entail substantial effort and cost.

## D. System and Unit Dispatch Data

Some methods, such as the base-intermediate-peak methods, require classification of units according to their primary operating function. This may involve judgmental classification by system planners or power system operators. Other methods, such as the probability of dispatch methods, require either actual or modeled data regarding specific units' operation on an hour-by-hour basis, as well as hourly load data. Production stacking methods require data on the dispatch configuration of units, including reserves, required to serve a given load level. Such data must be developed and maintained by the utility.

## E. Conclusion

This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.