

A FERC ELECTRIC RATE PRIMER

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This article addresses selected cost of service, allocation and rate design issues arising in Federal Energy Regulatory Commission (FERC or Commission) electric rate cases. It first focuses, in general terms, on how rates at FERC for an electric utility are derived. The article then discusses current subjects arising from the following: (1) operating expenses; (2) tax expense; (3) revenue issues; (4) rate base; (5) rate of return; (6) functionalization, classification, and allocation; and (7) rate design.

I. INTRODUCTION TO FERC ELECTRIC RATEMAKING

As a general matter, a utility is allowed to recover its cost of providing service plus a reasonable return on its investment.¹ The basic question in establishing utility rates is to determine the utility's total cost of service. This question seeks to determine how much in total revenue the utility should be authorized to collect through its rates in order to recover the costs that it incurs in providing electric service.²

The derivation of the cost of service or the revenue requirement may be expressed by the following formula:³

$$\text{Cost of Service} = E + d + T + (V - D)R$$

where:

- E = operating expenses
- d = depreciation expense
- T = Taxes
- V = Gross value of the property
- D = Accrued depreciation
- R = Overall rate of return

Components of this formula are derived from a twelve-month test period which is intended to be a representative period for the purpose of establishing rates. The test period in most instances will be a future test period, referred to in FERC's regulations as Period II.⁴

The formula set out *supra* is used to derive the utility's total revenue requirements. To establish rates for each wholesale customer class, it is necessary to eliminate the nonjurisdictional retail-related costs and to allocate the remaining costs among the wholesale classes.

Cost allocation involves three steps. The first step, functionalization, involves the segregation of expense items into categories according to their relationship to the utility's major operating functions, such as production, transmission, and distribution. This step also allows some of the nonjurisdictional retail-related costs to be eliminated from the cost allocation process. The next step is to classify these costs as either demand, energy, or customer costs. As a general matter, demand costs are

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¹See *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679, 692-9 (1923); *F.P.C. v. Hope Natural Gas Company*, 320 U.S. 591, 605 (1944).

²*Garfield and Lovejoy*, *Public Utility Economics* 44 (1964).

³*Id.* at 44-45.

⁴18 C.F.R. § 35.13(d)(1)-(2) (1983).

the fixed costs of providing service, such as the costs associated with the generating plants and the transmission facilities. Energy costs are the variable costs of providing service, such as fuel and some maintenance costs. Customer costs are those costs which are usually directly attributable to certain customers or customer classes, such as metering facilities. The third step is the allocation of these classified costs to the various wholesale classes.

Cost allocation assigns a specific amount of demand, energy, and customer related costs to each customer class. The rates or the unit charges are then determined through a process called "rate design." In deriving the demand charge, the estimated billing demand for the class will be divided into the total demand costs assigned to the class. This will result in a \$/KW demand charge.⁵ In deriving the energy charge, the estimated energy usage or Kwh's for the class will be divided into the total energy dollars assigned to the class in order to derive the energy charge in \$/Kwh.⁶ In addition, the allocated customer costs will often be used to derive a customer charge.⁷

II. OPERATING EXPENSES

As a general matter, if operating expenses are prudently incurred and relate to the provision of wholesale service, the utility will be allowed to recover the expenses from its wholesale customers. This section discusses issues that have arisen in connection with operating expenses sought to be recovered by electric utilities.

A. Reasonableness of Cost Projections

A leading case establishing standards for challenging cost projections (Period II estimates) of expenses is *Public Service Company of Indiana*, Opinion No. 783-A.⁸ The Commission stated therein:

A separate issue — the reasonableness of the validly propounded estimate — is presented. PSCI has the burden of not only supporting the methods used to derive its estimates but also to defend and substantiate such estimates as reasonable cost approximations. This, of course, does not imply that estimates, produced in good faith and in a sound manner, must be present. But the company must demonstrate that particular cost estimates are within a reasonable range, such that the overall cost of service proffered can assuredly be found to be a reflection of those costs which will actually be incurred in providing service to the public. Estimates, even though reasonable in conception, cannot be considered *pro tanto* impregnable. . . . Thus the standard applied must be understood to mean that particular items of expense, if challenged as excessive, must be demonstrated to have been *substantially* in error because of subsequent events which were not reasonably foreseeable at the time such estimate(s) were developed. We impose the requirement of substantiality because we feel that a certain degree of latitude is required in deference to the fact that unanticipated subsequent events normally act both ways.

⁵The demand charge is assessed for the customer's maximum load on the system, measured in kilowatt (KW) at a particular point in time.

⁶The energy charge is assessed for total electricity usage, measured in kilowatt hours (Kwh), over a specified period of time.

⁷Generally, low volume retail users, such as residences and small businesses, pay only an energy charge which may in fact be a blend of demand and energy charges. Typically, utilities design demand rates only for large customers, such as industries and wholesale buyers. In FERC practice, rates usually contain a demand charge, energy charge, and often a customer charge.

⁸57 F.P.C. 1173, 1182-83 (1977), *aff'd*, *Public Service Company of Indiana v. FERC*, 575 F.2d 1204 (7th Cir. 1978). *Accord* *Public Service Company of Indiana*, Opinion No. 44, 7 FERC ¶ 61,319 at 61,701 (1979); *Southern California Edison Company*, Opinion No. 55, 8 FERC ¶ 61,097 at 61,375 (1979); *Otter Tail Power Company*, Opinion No. 93, 12 FERC ¶ 61,169 at 61,428 (1980).

The D.C. Circuit in *NEPCO Municipal Rate Committee v. FERC*⁹ in approving this standard provided further clarification:

A utility must present a full explanation of the bases for test year cost estimates, establishing the validity and accuracy of each and the utility bears the burden of showing reasonableness in the increase requested. Once substantiated, those estimates become the bases for ratemaking unless a challenger can prove the projections unreasonable when made or that subsequent events indicate their use would yield unreasonable results.

Under these authorities, the burden is initially on the utility to justify its estimates and to show that its methodology is valid. If the utility meets that burden, then the burden shifts to the challenging party to demonstrate that either the estimates were unreasonable when made or that subsequent events make the use of the estimate unreasonable.¹⁰

B. Treatment of Atypical Expenses

The expenses includable in the cost of service should be typical and recurring. If expenses included in the test period are abnormal, atypical, or non-recurring, some adjustment to the cost of service may be ordered.

In *Public Service Company of Indiana*, Opinion No. 783-A,¹¹ the Commission stated that:

The company has a particular responsibility to . . . substantiate the Period II figure in terms of its typicality not only for the test period but also for the projected effective term of the tendered rates.

In *Boston Edison Company*, Opinion No. 53,¹² the Commission faced the question of abnormal nuclear maintenance expense. Boston Edison included the costs associated with a shutdown of its nuclear plant as part of its O&M expenses in its cost of service.¹³ The Commission examined the record evidence and found that the 1974 nuclear maintenance expenses which contained the shutdown costs were "unrepresentatively high while the 1973 expenses appear abnormally low."¹⁴ The Commission then averaged the 1973 and 1974 expenses.¹⁵

C. Treatment of Canceled Plant Expenses

As load growth has dropped off and as the cost of constructing plants has substantially increased, numerous power plants have been canceled after construction was well underway but before the plant was completed. The primary question that arises is how canceled plant costs should be treated in the cost of service. Generally, FERC has allowed either one-fifth or one-tenth of the canceled plant expenses to be included in the cost of service.

Six questions arise in connection with the costs of a canceled plant: (1) was the investment prudent? (2) what is an appropriate amortization period? (3) how should the deferred taxes associated with the tax loss resulting from the cancellation be treated? (4) how should the actual cancellation costs, which will be known after all

⁹668 F.2d 1327, 1339 (D.C. Cir. 1981), cert. denied, 457 U.S. 1117 (1982) (citations omitted).

¹⁰Id. See *Idaho Power Company*, Opinion No. 13, 3 FERC ¶ 61,108 at 61,294 (1978).

¹¹57 F.P.C. at 1182 (footnote omitted).

¹²8 FERC ¶ 61,077 at 61,279-80 (1979).

¹³Id. at 61,278

¹⁴Id. at 61,280.

¹⁵Id.

of the contracts have been settled, be taken into account? (5) what amount should be amortized? and (6) should the unamortized amounts be included in rate base?

1. Prudency

In *Minnesota Power and Light Company*, Opinion No. 86,¹⁶ the Commission established the general standard for prudency:

MP&L bears the burden of proving its entitlement to recovery of the costs associated with the scrubbers. . . . As a matter of practice, utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy or precedent otherwise require. However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.

In this case, record evidence indicates that the Minnesota Public Service Commission (MPSC) . . . disallowed the inclusion of the amortized extraordinary property loss as an operating expense in state rate cases. The MPSC order intimates that MP&L was improvident in the selection of the pollution control devices. Moreover, MP&L did not elect to appeal the decision of the MPSC. While we do not view state action as controlling, the MPSC opinion certainly constitutes more than a bare allegation of imprudence and is sufficient to draw into question the prudence of this expenditure. MP&L should have been prepared to come forward with specific evidence justifying the writeoff. This MP&L has not done.¹⁷

The Commission, though, has apparently found imprudence only in three cases and disallowed expenditures as a result of that imprudence.¹⁸ In addition, the Commission in two cases has disallowed extraordinary losses where a state commission has disallowed the writeoff, and the company failed to show that its actions were in fact proper.¹⁹

2. Amortization period

The first Commission decision on how to treat canceled plant costs was *New England Power Company*, Opinion No. 49, where the Commission held that a five-year amortization period was reasonable.²⁰ The other case involving this issue which has reached the Commission is *Northern States Power Company*²¹ wherein a ten-year amortization period was adopted. The Initial Decision stated:

¹⁶ 11 FERC ¶ 61,312 (1980). *Accord* Southern California Edison Company, Opinion No. 62, 8 FERC ¶ 61,198 at 61,679-80 (1979).

¹⁷ 11 FERC ¶ 61,312 at 61,644-45 (footnotes omitted).

¹⁸ *Minnesota Power and Light Company*, Opinion No. 87, 11 FERC ¶ 61,313 at 61,659-60 (1980) ("The combination of self-dealing, the selection of a questionable pollution control process, the failure either (or both) to secure a performance guarantee and to seek damages constitutes overwhelming evidence of imprudence"); *Public Service Company of New Hampshire*, Opinion No. 37, 6 FERC ¶ 61,299 at 61,714-15 (1979) (failure to pursue contractual remedies was improper); *Howard Metzenbaum v. Columbia Gas Transmission Corp.*, Opinion No. 25, 4 FERC ¶ 61,277 at 61,616-17 (1978) (pipeline had imprudently withdrawn gas from its storage reservoirs leading to emergency gas purchases at higher prices).

¹⁹ *Minnesota Power and Southern California Edison*, *supra* note 16.

²⁰ 8 FERC ¶ 61,054 at 61,176-7 (1979), *reh. denied*, Opinion No. 49-A, 10 FERC ¶ 61,279 (1980), *affirmed*, *NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327 (D.C. Cir. 1981), *cert. denied*, 457 U.S. 1117 (1982). *But see* *Virginia Electric and Power Company*, Initial Decision, 11 FERC ¶ 63,028 at 65,151 (1980), *affirmed*, Opinion No. 118, 15 FERC ¶ 61,052 (1981), (10-year amortization period allowed, though the appropriate amortization period not at issue).

²¹ Initial Decision, 13 FERC ¶ 63,049 at 65,292-93 (1980), *affirmed*, Opinion No. 134, 17 FERC ¶ 61,196 (1981), *affirmed sub nom.*, *South Dakota PUC v. FERC*, 690 F.2d 674 (8th Cir. 1982).

We conclude that the Staff's variable amortization period targeted at ten years should be adopted. . . . [T]his method will not result in an unique burden on ratepayers. The effect will be approximately one-half that of the company's proposal.²²

Of additional interest is that the Initial Decision in *Northern States* rejected a fifteen year amortization period:

The Wisconsin Cities' fifteen-year amortization proposal is likewise rejected. In determining the amortization period other factors than (sic) ratepayer impact are also important. Slavishly adopting the impact used in the *New England* Opinion No. 49 is not a sufficient basis for formulating the amortization period. The Commission in that Opinion said nothing in the nature of requiring that a 0.94% rate impact shall be used as the maximum for loss amortization in other cases.²³

Opinion No. 134²⁴ affirmed without discussion the *Northern States* Initial Decision. In *Carolina Power & Light Company*,²⁵ the ALJ held that a five-year amortization period was reasonable because the cost of service impact only was 0.28 percent. In *Pennsylvania Power Company*,²⁶ the ALJ determined that a ten-year amortization period was reasonable since there was only a 0.6 percent impact.

3. *Deferred taxes*

For ratemaking purposes, the tax deductions associated with the canceled plant losses are flowed through at the same time the canceled plant expenses are collected from the ratepayers. That is, the canceled plant expenses in the cost of service give rise to book tax deductions that are reflected in the cost of service. For tax purposes, however, a utility is able to declare the canceled plant as a tax loss at the time the cancellation occurs. This produces deferred taxes which are placed in Account 283.

Ordinarily, these deferred taxes would be used to reduce a utility's rate base since most Account 283 balances are subtracted from rate base. The Commission, however, in Opinion No. 134²⁷ disallowed such an adjustment:

Since the Tyrone project was never placed in service and its cost was never included in its rate base, Northern States will not earn a return on its Tyrone investment, will not have a corresponding tax obligation, and will neither need nor receive related tax compensation from its ratepayers. To deduct the unamortized deferred tax reserve balances from rate base would create a negative rate base and would therefore lower Northern States' cost-of-service by \$15 million over the course of a ten year normalization period. Were we to allow this to occur, we would effectively deprive Northern States from receiving compensation for its entire out-of-pocket investment in Tyrone.

Nor do we see any inequities in allowing Northern States to receive the use of the Account 283 balances. Since it will lose the time value use of its investment during the amortization period, it follows that it should receive the time value use of the unamortized tax benefits related to that investment during the normalization period.

4. *Variable amortization periods*

When plants are canceled, construction contracts must be canceled. These contract cancellations, though, take time to settle. Thus when a utility requests the

²² *Id.* at 65,293 (citations omitted).

²³ *Id.*

²⁴ 17 FERC ¶ 61,378 (1981).

²⁵ 17 FERC ¶ 63,040 at 65,138-89 (1981).

²⁶ 23 FERC ¶ 63,115 at 65,304-05 (1983).

²⁷ 17 FERC at 61,381-12 (footnote omitted). *Accord* Wisconsin Power and Light Company, Opinion No. 141, 19 FERC ¶ 61,288 at 61,569-70 (1982).

amortization of canceled plant costs, in most instances, the utility will have to estimate a large portion of those costs. In *Northern States Power Company*, Opinion No. 134,²⁸ a mechanism was adopted whereby the amortization period was lengthened or shortened depending upon the contract settlements. The amount collected each year, however, remains the same.

5. *Determining the amount to be amortized*

Two questions arise with respect to determining the amount of the cancellation loss to be amortized; (1) whether the gross or the net after tax amount should be amortized and (2) whether equity AFUDC²⁹ should be excluded from the amount to be amortized.

a. *Gross vs. net*

In *New England Power Company*, Opinion No. 49, the Commission rejected the argument that New England Power Company (NEP) should only be allowed to amortize its net (after-tax) loss.³⁰ The Commission held that NEP should be allowed to amortize its gross loss because "(i)f NEP is not permitted to write-off the gross loss of approximately \$13 million, it will not receive full recovery of the expenditures."³¹

The Commission, however, in *Wisconsin Power and Light Company*, Opinion No. 141,³² approved the write-off of a net-after-tax loss. In rejecting a proposal to amortize the gross loss and to simultaneously flow back the tax benefit of the deduction over the same amortization period the Commission stated that: "There is no difference in impact on the revenue requirement between the accounting methods of the company and staff.³³ From this it may be concluded, that the gross loss should be amortized except where there is no difference in impact between writing-off the gross or the net amounts.

b. *Equity AFUDC*

The costs of financing a plant under construction are included in an AFUDC account. These costs include both debt and equity financing.

The Commission in *Northern States Power Company*, held that equity AFUDC should be included in the amount of canceled plant losses to be amortized:

Further, we find it quite disturbing that the Judge singled out one component of construction cost (equity AFUDC) for disallowance from amortization. Equity AFUDC has traditionally been considered a component of construction cost and a very large portion of a utility's reported income results from its capitalization. For many utilities AFUDC is more than 50 percent of reported income. The only justification for the capitalization of equity AFUDC under generally accepted accounting principles is that ratemaking processes recognize the capitalized amounts as a legitimate construction cost and as such will

²⁸ See *supra* note 24.

²⁹ Allowance for funds used during construction (AFUDC) is a cost accounting procedure whereby the net composite interest and equity costs of capital funds used to finance construction are transferred from interest expense on the income statement to construction work in progress in the balance sheet. This procedure is intended to remove the effect of the cost of financing construction activity from the income statement, and results in treating such cost in the same manner as construction labor and material costs. See *infra* note 164.

³⁰ 8 FERC at 61,177.

³¹ *Id.*

³² 19 FERC ¶ 61,288 at 61,569 (1982).

³³ *Id.*

ultimately be recoverable from customers as the asset to which it relates is depreciated and recovered in rates. Investors and other readers of the financial statement of utilities have relied on these reported earnings over the years on the assurance that these capitalized amounts represent valid assets. If the Commission were to single out the reported equity AFUDC amounts from other components of construction cost, investors and other readers of financial statements would be justified in discounting the reported earnings of utilities even more than they presently do due to the non-cash nature of earnings attributable to AFUDC. This could have grave consequences to an already troubled electric industry and would not serve the public's interest in reliable service.³⁴

6. *Inclusion in rate base of unamortized amounts*

Electric utilities have argued that the unamortized portions of cancelled plant costs should be included in rate base. The Commission has, however, rejected this argument. In *New England Power Company*, the Commission in denying the inclusion of unamortized amounts in rate base stated:

There is no precedent, or reasonable justification in the record of this proceeding, to require ratepayers to pay a return on an expenditure that has not resulted in productive plant that is used or useful in the public service.³⁵

This holding was subsequently affirmed by the D.C. Circuit in *NEPCO Municipal Rate Committee v. FERC*.³⁶

D. *Customer Service — Sales — Conservation Expenses*

In *Arizona Public Service Company*, Opinion No. 177,³⁷ the Commission established the test to be applied in deciding whether to allow the inclusion of customer service, sales and conservation expenses. Under this test the utility must show a relationship between the expense and the wholesale service. While Opinion No. 177 and prior cases rejected the inclusion of customer service, sales and conservation expenses, that rejection was because the company failed to meet its burden of proof. In one case a small amount of customer service and sales expense was allowed to be assigned to the wholesale class where the record demonstrated that the expense was wholesale-related.³⁸

E. *Research and Development Contributions*

Electric utilities frequently make voluntary contributions to research associations or institutes engaged in research related to electric energy. Such expenses are often challenged by wholesale customers. The clearest statement of Commission policy on utility contributions to research and development organizations is set out in *Public Service Company of New Mexico*, (Opinion No. 133).³⁹ The Commission stated that Electric Power Research Institute (EPRI) dues could not be assigned to the wholesale class because wholesale customers could contribute

³⁴ 17 FERC at 61,383.

³⁵ 8 FERC at 61,175-76.

³⁶ See *supra* note 9.

³⁷ 23 FERC ¶ 61,419 at 61,930-01, 61,934 n.5. *Accord* *Arizona Public Service Company*, Initial Decision, 1 FERC ¶ 63,045 at 65,336 (1977), *affirmed*, 4 FERC ¶ 61,101 (1978); *Public Service Company of New Mexico*, Initial Decision, 10 FERC ¶ 63,020 at 65,134-6 (1980).

³⁸ *Carolina Power and Light Company*, Initial Decision, 4 FERC ¶ 63,015 at 65,151-2 (1977), *affirmed*, Opinion No. 19, 4 FERC ¶ 61,107 (1978), *reh. denied*, Opinion No. 19-A, 6 FERC ¶ 61,154 (1979).

³⁹ 17 FERC ¶ 61,123 at 61,248-49 (1981).

independently to EPRI. Similarly, contributions to the Liquid Metal Fast Breeder Program (LMFBR) cannot be flowed through to the wholesale class.⁴⁰ With respect to utility contributions to Edison Electric Institute (EEI), the Commission has held that such contributions can be charged in part to a utility's wholesale class of customers because they cannot make such contributions.⁴¹

F. Charitable and Political Contributions

There is a long line of Commission cases allowing the flowthrough of reasonable charitable contributions to the wholesale customers.⁴² The reasoning behind this is set out in *Municipal Light Boards*:

Reasonable donations are not only a duty, but are necessary to create and maintain good will toward the business, which undoubtedly results in lower overall costs of doing business than would be required in an atmosphere of ill will that would cause or intensify opposition to many actions the utility may wish to take.⁴³

A question, though, has arisen in at least one proceeding over what is a reasonable contribution. In *Union Electric*,⁴⁴ the company attempted to include \$600,000 of charitable contributions in its cost-of-service. While the ALJ held that reasonable contributions were allowable, he found Union's requested amount to be excessive and reduced the allowed charitable contribution to \$260,000.⁴⁵ The Commission in Opinion No. 205 reversed and stated:

Examination of the level of expenditure allowed to be included in another company's cost of service, in isolation, does not provide a rational basis for limiting the amount permitted here. While there may be a circumstance where charitable contributions are unreasonable in amount, nothing in this record indicates that this is such a case.⁴⁶

G. Regulatory Commission Expenses

In *Central Illinois Public Service Company*,⁴⁷ the ALJ stated:

It is a well-established principle of utility regulation that reasonable regulatory expenses are an appropriate item to be included in the cost-of-service. Such regulatory expenses are often amortized over a period to avoid any undue distortion of test year cost-of-service data. This is not to say, however, that a regulatory agency is precluded from evaluating the prudence of a regulatory expense and, where appropriate, disallowing it.

This portion of the Initial Decision was subsequently affirmed in Opinion No. 75.⁴⁸

In determining whether regulatory expenses are reasonable three questions arise: (1) whether the amortization period is appropriate; (2) whether prior rate

⁴⁰*Id.*; *Carolina Power*, 4 FERC at 65,152.

⁴¹*Public Service Company of New Mexico*, 17 FERC at 61,249; *Illinois Power Company*, 15 FERC ¶ 61,050 at 61,094 (1981); *but see Delmarva Power and Light Company*, Initial Decision, 22 FERC ¶ 63,052 at 65,188-9 (1983), *affirmed*, Opinion No. 189, 25 FERC 25 FERC ¶ 61,022 (1983).

⁴²*See Southern California Edison Company*, 59 FPC 2167, 2175, 2206 (1977); *Municipal Light Boards v. Boston Edison Company*, 53 FPC 1545, 1559 (1975); *affirmed*, *El Paso Natural Gas Company*, 46 FPC 454, 466-67 (1971); *United Gas Pipe Line Company*, 31 FPC 1180, 1189 (1964); *Union Electric Company*, Initial Decision, 21 FERC ¶ 63,080 at 65,236 (1982).

⁴³53 F.P.C. at 1559.

⁴⁴21 FERC at 65,235-36.

⁴⁵*Id.* at 65,236.

⁴⁶26 FERC ¶ 61,125 (mimeo ed. at 3) (Feb. 3, 1984).

⁴⁷8 FERC ¶ 63,022 at 65,196 (1979).

⁴⁸10 FERC ¶ 61,162 (1980).

case expenses can be recovered; and (3) whether the total amount of expense is reasonable.

1. *Amortization period*

In *Public Service Company of New Mexico*, Opinion No. 133,⁴⁹ the Commission stated that:

The precedents of the Federal Power Commission indicate that the total rate case expense reasonably incurred in a rate proceeding should be amortized over a period of time during which the rates established in the proceeding will be collected.

2. *Prior rate case expenses*

Prior rate case expenses generally are not includable. Opinion No. 133, *supra*, the Commission stated that: "(R)ate case expenses should be collected in the rates that result from the proceedings in connection with which they were incurred." In *Carolina Power and Light Company*,⁵⁰ the ALJ rejected the inclusion of such expenses:

The regulatory Commission expense allowed in each case is the total cost involved in litigating that case amortized over the period those rates are in effect. If a utility's filed rate proves insufficient to recover the full cost of providing services, this Commission is prohibited from setting rates to allow recovery of those past unrecovered costs. Hence, there is no guarantee that all of a utility's costs will be recovered. Some of them will "fall through the cracks"; and this is simply one of the risks to the utility of test year ratemaking.

3. *Reasonableness of the total amount*

The Commission has given little guidance on the reasonableness of the amount forecasted for regulatory expenses. The Commission has, however, stated that "proportionately large rate case expenses might tend to restrain public-owned wholesale customers from opposing such rate increases."⁵¹ The Commission also has established the test period amount by averaging the regulatory commission expenses for a five year period.⁵² Regulatory expenses, like other expenses, are subject to the standard that they must have been reasonable when made and must not produce an unreasonable result.⁵³

H. *Nuclear Decommissioning*

Decommissioning a nuclear facility is defined "as the measures taken at the end of the facility's operating life to assure the continued protection of the public from any residual radioactivity or other potential hazards present in the facility."⁵⁴ Decommissioning costs must be anticipated and assessed over the useful life of a nuclear generator so that ratepayers who benefit from the power produced also bear the cost of decommissioning.

While the Nuclear Regulatory Commission has jurisdiction over most matters involving decommissioning, the Commission shares jurisdiction over various

⁴⁹17 FERC ¶ 61,123 at 61,251 (1981).

⁵⁰17 FERC at 65,138 (footnotes omitted).

⁵¹Sierra Pacific Power Company, Opinion No. 730, 53 F.P.C. 1795, 1806 (1975); Boston Edison Company, Initial Decision, 8 FERC ¶ 63,048 at 65,491 (1979).

⁵²El Paso Natural Gas Company, Opinion No. 600, 46 F.P.C. 454, 468 (1971).

⁵³Public Service Company of Indiana, Opinion No. 783-A, *supra* note 8.

⁵⁴Battelle Pacific Northwest Laboratory, Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor, NUREG/CR-0130 (June 1978); Addendum (August 1979).

decommissioning issues in establishing rates for electric utilities. These issues are discussed in this section.

1. *Reasonableness of total decommissioning expenses*

The Commission first faced the question of nuclear decommissioning expenses in *Carolina Power and Light Company*, Opinion No. 19.⁵⁵

Since the widespread growth of nuclear generating facilities is a relatively recent occurrence, there is little hard evidence on which to establish a proper salvage rate for nuclear production plant. Pending further developments in this field we shall adopt the Law Judge's decision to base the depreciation expense for these properties on a zero salvage factor, without prejudice to a redetermination of this item when information becomes available.

In *Connecticut Light and Power Company*,⁵⁶ CL&P submitted studies estimating the decommissioning costs of Millstone 1 and 2. These studies estimated decommissioning costs for these two units of: (1) \$18.9 million if mothballing is used; (2) \$67.8 million if entombment is used; and (3) \$118.5 million if complete dismantlement is used. CL&P requested that entombment be used to establish rates, though it considered complete dismantlement to be preferable. Staff in that case argued for mothballing. The ALJ accepted the staff position:

Recognizing the present unsettled character of the problem and its pendency elsewhere, the long time frame involved prior to any actual decommissioning of those relatively newly built nuclear units, and the current acceptability of mothballing, the Presiding Judge finds that the Commission Staff's position is the more reasonable approach and that its estimated negative salvage values are more appropriate for the purposes of this rate proceeding. This finding, however, is without prejudice, of course, to a full reexamination of the question in any future rate proceeding in the light of the facts then existing.⁵⁷

The Commission affirmed the ALJ's decision in Opinion No. 102:⁵⁸

Our task is not to designate a method of decommissioning. That is the responsibility of the Nuclear Regulatory Commission. . . . Whatever methodology is selected, however, it is clear that the present generation of electric ratepayers should pay a fair share of the known but unquantifiable cost of nuclear plant decommissioning since the present generation benefits from the use of those plants.

. . . Given the highly speculative nature of the matter at this time, we are reluctant to allow a charge to be assessed that may exceed on a proportionate basis the true cost of decommissioning. We are reasonably confident that the mothballing projection reflects at least the minimum that will be needed to effect decommissioning. Therefore, the mothballing figure carries with it the least degree of uncertainty.

In *Connecticut Yankee Atomic Power Company*,⁵⁹ the ALJ chose mothballing primarily because it was the most conservative approach.⁶⁰ This part of his decision was affirmed by the Commission in Opinion No. 102.⁶¹ In *Maine Yankee Atomic Power*

⁵⁵ 4 FERC ¶ 61,107 at 61,225 (1978).

⁵⁶ Initial Decision, 5 FERC ¶ 63,004 at 65,075-6 (1978), *affirmed*, Opinion No. 103, 13 FERC ¶ 61,155 at 61,332-3 (1980).

⁵⁷ 5 FERC at 65,075.

⁵⁸ 13 FERC at 61,332-33.

⁵⁹ Initial Decision, 10 FERC ¶ 63,018 (1980), *affirmed*, Opinion No. 102, 13 FERC ¶ 61,154 at 61,329 (1981).

⁶⁰ *Id.* 10 FERC at 65,107.

⁶¹ 13 FERC at 61,329.

Company,⁶² the Commission approved a contested settlement which included a decommissioning cost based on immediate dismantlement. In *Pacific Gas & Electric Company*,⁶³ the judge rejected the utility's total proposed decommissioning expenses because of the lack of support evidence. The Commission affirmed the ALJ on this issue.⁶⁴ Recently, in a *Middle South Energy* initial decision, the ALJ accepted a decommissioning estimate of 93.3 million dollars based, *inter alia*, on the immediate dismantlement method.⁶⁵

2. Reasonableness of annual decommissioning expenses

The next step in deriving the annual decommissioning expense is to develop an estimate of the plant's remaining life. The Commission in *Carolina Power and Light Company*⁶⁶ in discussing nuclear depreciation rates stated:

[E]mpirical data concerning nuclear plant depreciation rates is almost totally lacking. Consequently, we will use the 25 year period as representing a reasonable estimation at this time. If, in the future, it develops that a 4.0% annual depreciation rate is no longer appropriate, an adjustment will be made to account for any significant under or over accumulations.

One factor that can be used to determine the remaining life of a nuclear plant is the remaining life of the operating license for the plant issued by the NRC. This position recently was adopted by an ALJ in *Middle South Energy*.⁶⁷ Another factor which enters into determining the annual decommissioning accrual is determining an annual growth rate for the funds. In some cases decommissioning expenses have been recovered through the depreciation rates as a negative salvage.⁶⁸ In those cases no earnings on the decommissioning funds were factored into the determination of an annual amount. In other cases a sinking fund has been established.⁶⁹ This sinking fund is used to reduce the annual decommissioning amounts by taking into account the earnings from the fund. A question that arises is of the appropriate growth rate to use for the fund. In *Maine Yankee* the Commission approved an annual decommissioning accrual which was derived assuming a real three percent growth rate.⁷⁰ A three percent growth rate also was recently adopted by an ALJ in *Mid-South Energy*.⁷¹

3. External vs. internal fund

If a utility has an internal sinking fund or if a negative salvage is used to collect decommissioning dollars, then the utility will have the use of the decommissioning dollars to meet its day-to-day obligations. The decommissioning dollars would only

⁶² 20 FERC ¶ 61,141 (1982), *affirmed sub nom.*, *Ashburnham Municipal Light Department v. FERC*, No. 82-2332 (D.C. Cir. June 1, 1983).

⁶³ 16 FERC ¶ 63,004 at 65,007-8 (1981), *affirmed*, Opinion No. 147, 20 FERC ¶ 61,340 at 61,709 (1982).

⁶⁴ 20 FERC at 61,709.

⁶⁵ 26 FERC ¶ 63,044 mimeo ed. at 79-82 (February 3, 1984).

⁶⁶ 4 FERC at 61,226. Depreciation rates or decommissioning accruals based on a remaining life for a nuclear plant of 28 years (*Boston Edison Company*, 8 FERC ¶ 63,048 at 65,507 n.106 (1979)) and 22 years (*Maine Yankee*, 20 FERC at 61,308) also have been approved.

⁶⁷ 26 FERC ¶ 63,044 mimeo ed. at 83.

⁶⁸ See, e.g., *Connecticut Light and Power*, 13 FERC at 61,332.

⁶⁹ See *Maine Yankee Atomic*, 20 FERC at 61,308.

⁷⁰ *Id.* 20 FERC at 61,308.

⁷¹ 26 FERC ¶ 63,044 mimeo at 83.

"show up" as an accounting entry on the utility's books without any funds being separately segregated.

If an external fund is established, the decommissioning dollars would be placed in a trust fund which the utility could not use. In *Connecticut Yankee*,⁷² the ALJ rejected the use of a separate external fund for Connecticut Yankee, a single asset company:

[I]t seems unnecessary to create a segregated fund for the portion of Connecticut Yankee's revenues that is attributable to negative salvage charges. In light of the additional expense such a funding requirement would impose and the marginal public benefits that might result from it at best, the Commission will not require Connecticut Yankee to establish an escrow fund at this time.⁷³

The Commission in Opinion No. 102, while not requiring that an external fund be established, did not adopt the ALJ's rationale nor did it foreclose the acceptance of an external fund in another proceeding.⁷⁴

In *Boston Edison Company*, Opinion No. 156,⁷⁵ the Commission was faced with the question of whether funds collected for spent nuclear fuel disposal should be accumulated in an external fund. The Commission, while rejecting the adoption of an external fund, did state that:

We recognize, however, that there might be future cases where a segregated trust fund approach would be appropriate because it provides assurance that a company will be financially able to pay the SNF costs at the time they are actually incurred some years in the future. There well may be a situation where the Commission would give greater weight to this safety risk argument, particularly where a utility is a single asset company or where it is in poor financial condition. That is not true in this particular case, and we believe the overall factors pointed out by the judge favor approval of Edison's approach.⁷⁶

I. *Spent Nuclear Fuel Disposal Costs*

A nuclear power plant is fueled by rods containing pellets of enriched uranium,⁷⁷ which are assembled in bundles in the reactor core. As a result of the highly radioactive nature of the spent fuel rods — a condition which will exist for a very long time — the fuel rods must be disposed of in such a manner so as not to endanger the public. Spent fuel disposal — the techniques and costs of which are still not totally certain — will occur in the 1990's at the earliest and involve substantial sums of money. In order to ensure that today's ratepayers pay their fair share of the costs, a charge should be included in the current rates for spent nuclear fuel disposal costs (SNFDC).⁷⁸ Three options for spent nuclear fuel are possible. Spent fuel can be reprocessed. It also can be stored "temporarily," or it can be disposed of permanently.

⁷²See *supra* note 59.

⁷³10 FERC at 65,108.

⁷⁴See 13 FERC at 61,329.

⁷⁵21 FERC ¶ 61,327 (1982).

⁷⁶*Id.* at 61,881 (footnote omitted).

⁷⁷Enriched uranium for civilian power plants is a mixture which usually includes 97% uranium-238 and 3% uranium-235.

⁷⁸See *Virginia Electric and Power Company*, Opinion No. 118, 15 FERC ¶ 61,052 at 61,105. (1981); *Boston Edison Company*, 21 FERC at 61,879 (1982).

Prior to the Nuclear Waste Policy Act of 1982,⁷⁹ the determination of the SNFDC amounts was a complex and often litigated issue. Three Commission decisions on SNFDC were issued before the Act became effective. In *Virginia Electric and Power Company*, Opinion No. 118,⁸⁰ the Commission disallowed permanent disposal costs because of the "uncertainty that exists concerning the federal reprocessing policy." The Commission allow interim away from reactor (AFR) storage costs to be recovered. In *Carolina Power and Light Company*, Opinion No. 132,⁸¹ the Commission disallowed permanent disposal costs and recovery of any SNFDC because of the lack of record evidence.⁸² In contrast, *Boston Edison*, Opinion No. 156,⁸³ the Commission allowed the recovery of permanent disposal costs because the record in that case clearly showed that there would be permanent disposal costs even if there were reprocessing.

The passage of the Nuclear Waste Policy Act of 1982, makes these cases of limited value. Section 302(a)(2) of the Act establishes a fee of 1 mill per kilowatt-hour for SNFDC to be paid by each electric utility for gross generation from April 7, 1983 forward.⁸⁴ For spent fuel which was used to generate electricity prior to April 7, 1983, Section 302(a)(3) of the Act provides for the establishment of a one time fee per kilogram of heavy metal with the fee being "in an amount equivalent to an average charge of 1.0 mill per kilowatt-hour".

An issue which may arise is how these amounts for pre-April 7, 1983 spent fuel should be reflected in the cost of service. In the only two cases where the Commission has allowed the recovery of costs for previously burned spent fuel, such costs have been amortized over a specific time period.⁸⁵ In *Virginia Electric and Power Company*, the Commission adopted a ten-year amortization period for previously burned nuclear fuel.⁸⁶ In *Boston Edison* the ALJ stated:

Following *Vepco*, the Towns would apparently amortize the SNFDC charge for previously utilized fuel over a shorter period, i.e., 10 years, than Edison's 9-14 years. This would impose a faster recovery and higher charges against the current ratepayers. However, *Vepco* allowed SNFDC recovery only for interim, AFR storage (which was then thought to take place in a few years) and no rule was laid down for an amortization period for permanent disposal cost recovery. Since we should tie the projected time of permanent disposal, and that time on this record is 1997 at the earliest, the amortization period should extend from July, 1980, when Edison first imposed the charge, to 1997, or seventeen years. This will require a modest amount of refunds to Edison's customers who have paid the charge on the basis of a 9-14 year amortization period.⁸⁷

The Commission affirmed the ALJ on this issue.⁸⁸

⁷⁹ Pub. L. No. 97-425, 96 Stat. 2201 (enacted Jan. 7, 1983), 42 U.S.C. §§ 10101, *et seq.*

⁸⁰ 15 FERC at 61,105.

⁸¹ 17 FERC ¶ 61,118 (1981), *remanded*, *Carolina Power & Light Co. v. FERC*, 716 F.2d 52 (D.C. Cir. 1983).

⁸² *Id.* 17 FERC at 61,239.

⁸³ 21 FERC at 61,878-80.

⁸⁴ See 48 Fed. Reg. 16,591.

⁸⁵ *Virginia Electric and Power Company*, 15 FERC at 61,105-06; *Boston Edison*, 21 FERC at 61,881.

⁸⁶ 10 FERC at 61,105-6.

⁸⁷ 18 FERC at 65,179.

⁸⁸ 21 FERC at 61,881.

III. TAX EXPENSE

A. Normalization

In Order No. 144,⁸⁹ this Commission required utilities to utilize tax normalization for all timing differences. In "normalizing" a transaction, straight-line depreciation is used in developing the tax allowance in the cost of service. The difference resulting from the use of accelerated depreciation and the use of straight line depreciation results in deferred taxes which are placed into Account No. 282 and deducted from rate base. The utility has the use of the dollars resulting from accelerated depreciation because normalization precludes the immediate flow-through of those dollars. However the utility is precluded from earning a return on those dollars because of the rate base reduction.

FERC has not had a consistent normalization policy with respect to all timing differences throughout the years. Tax benefits with respect to certain items that are currently required to be normalized have been flowed-through to the ratepayers. As a result, utilities may have deficiencies in their deferred tax accounts. Order No. 144 requires that these deficiencies (or excess amounts) be eliminated.⁹⁰ The question that arises is the amortization period that should be used in eliminating this deficiency. The Commission, in Order No. 144 stated:

As revised, the final rule requires rate applicants to begin the process of making up deficiencies in or eliminating excesses in their deferred tax reserves so that, *within a reasonable period of time to be determined on a case-by-case basis*, they will be operating under a full normalization policy. . . .

Since the appropriateness of any method to accomplish the objective of full normalization at current tax rates has not been analyzed by the Commission on a generic basis, the Commission is, at this time, requiring resolution of this problem on a case-by-case basis. As the issue is resolved in a number of cases, one or more specific methods . . . that would have wide applicability may be adopted.⁹¹

In *Natural Gas Pipeline Company of America*, Opinion No. 108,⁹² the Commission adopted the *South Georgia* method and amortized the deficiency over the remaining book life of the property. That holding may not be controlling because the Commission refused to adopt it in Order No. 144.⁹³

Since Order No. 144 was issued, this question has been litigated in a number of cases. None of these cases has reached the Commission and only one has resulted in an initial decision. In *Pennsylvania Power Company*,⁹⁴ the Company proposed a 10-year amortization period. The intervenors argued for a 25-year amortization period which was the remaining book life. The ALJ held that a 10-year amortization period was appropriate:

Certainly, the 10 years comes closer to the requirement of "a reasonable period of time" than the 25 years proposed by the Boroughs. Moreover, the use of a 10-year period more closely matches the ratepayers who will bear the burden of marking up the deficiencies in deferred

⁸⁹FERC Statutes and Regulations, Regulations Preambles 1977-1981, ¶ 30,254, at 31,539 (May 21, 1981); *reh. denied*, Order No. 144-A, *affirmed*, *Public Service v. FERC*, 709 F.2d 73 (D.C. Cir. 1983).

⁹⁰See *Public Systems v. FERC*, 709 F.2d 73 (D.C. Cir. 1983) (*Public Systems II*).

⁹¹1977-1981 Reg. Preamble at 31,560 (emphasis added).

⁹²13 FERC ¶ 61,266 at 61,588 (1980).

⁹³1977-1981 Reg. Preamble at 31,560.

⁹⁴Initial Decision, 23 FERC ¶ 63,115 at 65,301 (1983).

tax reserves with those ratepayers who received the benefit of flow-through in the form of lower rates. And, although reached by a different approach, 10 years was found reasonable in *Natural Gas Pipeline Co., supra*.

The benefit to past ratepayers is that if rates for service had been established during the 10-year period in which the deficiency arose on the basis of full normalization, the deficiency would not exist. Therefore, at least for part of that period, rates for service would have been higher than they actually were because there would have been a greater charge to income tax expense. The ratepayers who received the benefit of lower rates should be the ones to make up the deficiencies. There is a stronger likelihood that there will be a closer matching of the same customers who received service from 1970 to 1980 over the period 1980 to 1990, than would be the case in spreading the recovery over the next 25 years.

I conclude that the Company's proposal should be adopted because the proposed 10-year period is a "reasonable period of time" under Order No. 144, the deficiency arose over a 10-year period and there is a greater likelihood of matching customer benefits with recovery of the deficiency.⁹⁵

B. Investment Tax Credits

The primary issues that arise with respect to tax credits are: (1) the amount of tax credits that should be flowed-through to the ratepayers; (2) whether accumulated deferred investment tax credits (ADITC) should earn a common equity return; (3) whether tax credits on qualified progress expenditures (QPE's) generated during the construction period should be flowed-through to the ratepayers before the plant goes into service; and (4) whether generated but unutilized tax credits should be considered in deriving the test period tax credit balances.

1. Tax credit flow-through

Two issues have been litigated at FERC on the tax credit amounts to be flowed through to the ratepayers: (1) whether for an option 3 company, 100 percent or a ratable portion of the tax credits should be flowed-through to the ratepayers; and (2) whether all tax credits should be flowed-through to the shareholders.

The Commission has accepted three different approaches as to whether 100 percent or a ratable portion of tax credits should be flowed through to the ratepayers. In *Southern California Edison Company*,⁹⁶ the ALJ held that the four percent tax credit should be immediately flowed through to the ratepayers. He rejected arguments that it should be normalized.⁹⁷ The Commission in Opinion No. 62 affirmed the ALJ on this issue.⁹⁸

In *Connecticut Light and Power Company*, the ALJ rejected an argument that the utility as an option 3 company should immediately flow-through 100 percent of its ITC's to the ratepayers:

While Section 46(f)(3) permits them to flow through these investment tax credits, it does not require them to do so. An election under Section 46(f)(3) is merely one not to be subject to restrictions on flowing through the credits. Thus, it is no bar to a change to some form of

⁹⁵ *Id.* at 65,302.

⁹⁶ Initial Decision, 3 FERC ¶ 63,033 at 65,217-8 (1978).

⁹⁷ *Id.* at 65,218.

⁹⁸ 8 FERC ¶ 61,198 at 61,677 (1979); accord, *Southern California Edison Company*, Opinion No. 145, 20 FERC ¶ 61,301 at 61,586 (1982), affirming, Initial Decision, 17 FERC ¶ 63,026 at 65,062-3 (1981); see *Arizona Public Service Company*, Initial Decision, 1 FERC ¶ 63,045 at 65,333-4 (1977), affirmed, 4 FERC ¶ 61,101 at 61,209 (1978).

normalization. Moreover, Connecticut Light and Power Company's request to normalize the investment tax credits is consistent with the purpose of Section 46(f). The change will share these advantages of the investment tax credit with the investor, as well as the ratepayer, to stimulate the attraction of capital and maintain Federal income tax revenues.⁹⁹

Thus the ALJ allowed the utility to ratably flow-through the tax credits. The Commission in Opinion No. 103 affirmed.¹⁰⁰ In *Delmarva Power and Light Company*,¹⁰¹ the Commission, while ratably amortizing the tax credits for an option 3 company over the life of the property, also reduced the rate base by the unamortized amounts.

In *Southwestern Public Service*,¹⁰² the Company argued that it should be allowed to retain 100 percent of its tax credits. The staff and the intervenors in that case opposed the Company's proposal. The Commission held that the tax credits in that case should be shared between the ratepayers and the Company through a ratable reduction in the cost of service. In doing so, the Commission stated that its past policy has been to require that the tax credits for electric utilities be shared.

2. Accumulated Deferred Investment Tax Credit (ADITC)

Accumulated Deferred Investment Tax Credits (ADITC) are tax credits which have not yet been passed on to the ratepayers under the options presented by section 46(f) of the Internal Revenue Code. A question that has arisen is whether ADITC balances should be included in the equity component of the capital structure. It has been held that the ADITC balances should either be included in the capital structure in the same proportions as the debt, preferred, and common equity already in the capital structure or be excluded completely from the capital structure since both approaches produce the same result.¹⁰³

3. Tax credits generated on Qualified Progress Expenditures (QPE's)

The Tax Reduction Act of 1975¹⁰⁴ provides that tax credits generated by expenditures made with respect to Qualified Progress Expenditure property could be utilized by the utility in the year in which the expenditure was made even if the plant was not in service. A question arises, though, as to whether the flow-through of these tax credits should begin before the plant goes into service. *Southern California Edison Company*¹⁰⁵ held that the flow-through of the investment tax credits should not begin until the plant goes into service.

4. Generated but unutilized tax credits

As a result of insufficient earnings and large construction programs, a number of utilities have in past years been unable to utilize all of the tax credits that were

⁹⁹ Initial Decision, 5 FERC at 65,077.

¹⁰⁰ 13 FERC at 61,331.

¹⁰¹ Opinion No. 185, 24 FERC ¶ 61,199 at 61,457-8 (1983).

¹⁰² Opinion No. 162, 22 FERC ¶ 61,341 (1983). *But see* Public Service Company of New Mexico v. FERC, 653 F.2d 681, 685 (D.C. Cir. 1981); NEPCO Municipal Rate Committee, 668 F.2d at 1336; Union Electric Company v. FERC, 668 F.2d 389, 395 (8th Cir. 1981); H.R. Rep. No. 533, 92nd Cong., 1st Sess., reprinted in (1971) U.S. Code Cong. & Ad. News 1825, 1839-40; Carolina Power, Opinion No. 19, 4 FERC at 61,227.

¹⁰³ See e.g., Carolina Power & Light Company, Opinion No. 19, 4 FERC at 61,226-8; Public Service Company of New Mexico v. FERC, 653 F.2d 681 (D.C. Cir. 1981).

¹⁰⁴ Pub. L. No. 94-12 (1975).

¹⁰⁵ Opinion No. 145, 20 FERC ¶ 61,301 (1982), *affirming*, Initial Decision, 17 FERC ¶ 63,026 at 65,063-4 (1981); *accord*, Carolina Power and Light Company, Initial Decision, 17 FERC ¶ 63,040 at 65,141-2 (1981).

generated. In *Virginia Electric and Power Company*, Opinion No. 118-A,¹⁰⁶ the Commission stated:

Reducing rates through the amortization of generated but unused investment tax credits would result in passing benefits to ratepayers prior to the time that the benefits are realized by VEPCO. This result is clearly unfair since, under *ElectriCities* scheme, VEPCO would be required for a time to finance a portion of its cost of service without compensation. Such lack of reimbursement of financing costs would continue until the investment tax credits ultimately were used to reduce VEPCO's tax liability. In contrast, *ElectriCities* approach to investment tax credits would not permit VEPCO to recoup its costs of financing the investment tax credits amortized in rates prior to the time VEPCO is able to use those credits in its tax filing.

Thus it can be concluded that generated but unutilized tax credits should not be used to reduce the cost of service.

C. Stand-Alone Approach

In *Columbia Gulf Transmission Company*, Opinion No. 173,¹⁰⁷ which was decided upon remand of the D.C. Circuit,¹⁰⁸ the Commission established that the test for determining whether a portion of the consolidated tax savings should be shared with the ratepayer "is whether the expenses that generate the deduction are used to determine the jurisdictional service's rates."¹⁰⁹ In other words, if an expense which gave rise to a consolidated tax savings is charged to the ratepayers, they should receive the tax benefits associated with that expense:

[O]ur stand-alone policy in effect looks beneath the single consolidated tax liability and analyzes each of the deductions used to reduce the group's tax liability to determine the deductions for which each service is responsible. It then allocates to the jurisdictional service those deductions which were generated by expenses incurred in providing that service.

In short, the response has been to try to regulate the pipeline as an 'independent entity' so that it is 'considered as nearly as possible on its own merits and not on those of its affiliates.'¹¹⁰

The pipeline's parent in *Columbia Gulf* had a tax loss because its tax deduction for the interest expense it incurred in servicing its debt exceeded its income. Because the parent's interest expense was used in the pipeline's capital structure in establishing rates, the ratepayers bore the burden of paying the parent's interest expense.¹¹¹ The Commission, though, held that, because the cost of service contained an interest deduction calculated by multiplying the weighted cost of long term debt in the capital structure by the rate base, the tax savings resulting from the

¹⁰⁶ 17 FERC ¶ 61,150 at 61,295-6 (1981); see also *Arizona Public Service Company*, Opinion No. 137-A, 20 FERC ¶ 61,407 at 61,824-5 (1982) (Non-electric income cannot be used in deriving the test period amount of tax credits).

¹⁰⁷ 23 FERC ¶ 61,396 (1983); accord, *Potomac Edison Company*, Opinion No. 163-A, 23 FERC ¶ 61,398 (1983); *Southern Natural Gas Company*, Opinion No. 174, 23 FERC ¶ 61,397 (1983).

¹⁰⁸ *City of Charlottesville v. FERC*, 661 F.2d 945 952, 954 (1981).

¹⁰⁹ The Commission has in the 1940's and 1950's flowed through consolidated tax savings to the ratepayers, though, since 1972, it has adhered to the policy set out in *Columbia*, 23 FERC at 61,852, 61,854.

¹¹⁰ 23 FERC at 61,853, 61,860; accord, *Louisiana Power and Light Company*, Opinion No. 110, 14 FERC ¶ 61,075 at 61,124 (1981); *Southern California Edison Company*, Opinion No. 821, 59 F.P.C. 2167, 2174 (1977).

¹¹¹ *Id.* 23 FERC at 61,852-5 (footnote omitted).

parent's interest expense had already been flowed-through to the ratepayers.¹¹² Thus the Commission made no further adjustment to the pipeline's tax allowance.

IV. CERTAIN REVENUE ISSUES

A. Fuel Synchronization

The Commission initially approved a fuel synchronization adjustment in *Alabama Power Company*, Opinion No. 54.¹¹³ However, the leading Commission statement is *Utah Power and Light Company*, Opinion No. 114:¹¹⁴

We disagree with the judge that synchronization of fuel revenues and fuel expenses will yield an unreasonable result. The staff's proposed synchronization is consistent with test year cost of service principles and the particular fuel clause filed in this proceeding. Furthermore, although it is possible that Utah could experience a shortfall in revenues collected during the test year, this is because Utah bases its fuel adjustment charge on the actual costs of a preceding month. The risk involved in the selection of a fuel adjustment clause is on the utility, and until such time as Utah may decide to change its method of estimating the fuel adjustment charge, it will necessarily experience a lag in the revenues received.

One offshoot which has recently been litigated is whether a utility with a lagging fuel clause which is being subjected to a fuel synchronization adjustment should have its fuel clause treated as self-synchronizing¹¹⁵ for purposes of determining the compliance rate and for purposes of determining any refunds. It has been held, however, that a self-synchronizing fuel clause should not be adopted retroactively where the party is only trying to eliminate the effect of the fuel synchronization adjustment.¹¹⁶

B. Revenue Credit vs. Cost Allocation

In *Public Service Company of New Mexico*, Opinion No. 146,¹¹⁷ the Commission held that, for opportunity sales, a revenue credit should be used:

There are good reasons for preferring the revenue credit to cost allocation in reflecting opportunity sale transactions in native load customer rates. Cost allocation is simply not feasible in many cases. For many interruptible sales it is impossible to know beforehand, at the time native load rates are being adjusted, the quantities that will be sold during the test year or during the period those rates will be in effect. In many sales, it is not possible to predict from which unit or units a particular customer will be served.

... The capacity used in an opportunity sale was planned for the native load and will be used to serve those customers when needed. A consistent policy of revenue crediting avoids

¹¹²*Id.* at 61,853.

¹¹³8 FERC ¶ 61,083 at 61,326 (1979).

¹¹⁴14 FERC ¶ 61,162 at 61,297 (1981) (footnote omitted). *Accord* Wisconsin Power and Light Company, 23 FERC ¶ 61,288 (1983); Mississippi Power Company, 22 FERC ¶ 61,141 (1983).

¹¹⁵A self-synchronizing fuel clause is one that eliminates the lag. Under this type of clause usually the fuel expenses for a particular month will be in part actual and in part estimates. A bill will go out reflecting those expenses. The estimate will then be true-up in the following month. Adoption of a self-synchronizing fuel clause eliminates the need for a fuel synchronization adjustment.

¹¹⁶Kentucky Utilities Co. Initial Decision, 22 FERC ¶ 63,011 at 65,045-6 (1983), *affirmed*, Opinion No. 184, 24 FERC 61,158 mimeo at 8 (1983). If a utility changes to a self-synchronizing fuel clause on a prospective basis, it will probably lose dollars which it may never recover as a result of the elimination of the lag. See *Public Service Co. of New Hampshire v. FERC*, 600 F.2d 944 (D.C. Cir.), *cert. denied*, 444 U.S. 990 (1979).

¹¹⁷20 FERC ¶ 61,290 at 61,546-8 (1982) (citations omitted).

the administrative problems of making rate base adjustments each time a utility has made an opportunity sale.¹¹⁸

In *Ohio Edison Company*, Opinion No. 170,¹¹⁹ the Commission stated that net interchange revenues (such as revenues from economy, emergency, and short-term sales) must be used as a credit to the cost of service.

In *Boston Edison Company*, Opinion No. 53,¹²⁰ it was stated:

Upon consideration of this issue the Commission finds that allocation of costs to the firm services in question is preferable to Edison's revenue credit approach. . . . Where information is readily available by which the proper allocation of costs can be made, it seems reasonable to do so and thereby to avoid the uncertainty as to whether the revenues may or may not be compensatory. . . .

It should be noted, however, that in certain circumstances, where the revenues produced from a firm sale are insufficient — thus resulting in subsidization by the wholesale class — the Commission has adopted a revenue credit approach. This has been done only when the wholesale customers are receiving some other benefit in addition to the revenues from the unit sale.¹²¹

V. RATE BASE

A fertile area for litigation is working capital. Another area which has been and in future years should be the subject of substantial litigation is CWIP, particularly as a result of the Commission's recent rulemaking order allowing the inclusion of CWIP in the rate base.¹²²

A. Working Capital

1. Cash working capital

In describing the need for a cash working capital allowance this Commission has stated that:

A utility is permitted to include in its rate base an allowance for the cash needed to meet operating expenses for the period during which the utility has provided services to its customers and has not been paid for those services. Since all the operating expenses will eventually be paid out of revenues received by the utility, the need for working capital arises largely from the time lag between the utility's payment of expenses incurred in the rendition of service and the receipt of payments therefor.¹²³

In *Interstate Power Company*,¹²⁴ the FPC adopted a procedure whereby a utility's cash working capital allowance would be calculated based upon 45 days of estimated operation and maintenance expenditures less purchased power costs. Until recent

¹¹⁸ *Id.* at 61,547.

¹¹⁹ 23 FERC ¶ 61,344 at 61,756 n.46 (1983).

¹²⁰ 8 FERC ¶ 61,077 at 61,283 (1979); *accord*, *Arizona Public Service*, 13 FERC at 65,221, *affirmed*, 18 FERC ¶ 61,197; *Arizona Public Service*, 21 FERC at 65,097, *affirmed*, 23 FERC 61,419.

¹²¹ *See, e.g.*, *Arizona Public Service Company*, Opinion No. 137, 18 FERC at 61,394-45; *Virginia Electric and Power Company*, Opinion No. 118, 15 FERC at 61,111.

¹²² Order No. 298, *Construction Work in Progress for Public Utilities*, 48 Fed. Reg. 24,323 (1983).

¹²³ *Pennsylvania Power Company*, Opinion No. 89, 12 FERC ¶ 61,049 at 61,078 (1980) (footnote omitted); *Louisiana Power and Light Company*, Opinion No. 110, 14 FERC ¶ 61,075 at 61,120 (1981).

¹²⁴ 2 F.P.C. 71, 85 (1939).

years, the 45 day approach was "found to produce a reasonable approximation of a utility's working capital needs."¹²⁵

In *Carolina Power and Light Company*, Opinion No. 19-A,¹²⁶ the Commission stated that it was reevaluating the 45-day rule and as such was establishing interim procedures:

During the interim period our course will be as follows. Where a fully developed and reliable lead-lag study is available in the record, we will utilize that study to determine the working capital allowance. Where a study meeting these criteria is not available we will continue to apply the 45-day convention. However, two adjustments will be made in the latter instance, provided the information is available. Fossil fuel expense has come to represent a major expense item for many utilities and, therefore, as substantial component of the O&M expenses. Where this is the case, and the actual lag in the payment for fossil fuel is known, the amount thereof will be substituted as an adjustment to the results otherwise attained by the 45-day rule.

Second, where an adjustment for fuel expense lag is made, a further adjustment will be performed, as an add-on to the results under the formula, to recognize the increased importance to the utilities of purchased power expense. This item has not heretofore been comprehended within the operation of the rule. In our opinion, the combination of these two adjustments with the formulary method will produce a more accurate reflection of the utility's actual operating cash needs.

a. Lead-lag studies

A lead lag study is used to approximate the actual cash needs of a utility. There are two major components to a lead lag study: (1) a revenue lag and (2) an expense payment lag. In order for a lead lag study to be accepted at the Commission, it must be "fully developed and reliable." The Commission has, however, given minimal guidance as to what is meant by that phrase.

In *Pennsylvania Power Company*, Opinion No. 89,¹²⁷ the Commission stated that:

Our purpose in imposing the 'fully developed and reliable' standard was to require lead-lag studies to be prepared in such a way that the Commission can be reasonably confident that the study reflects the actual, rather than just an approximation of, the cash needs of the utility.

In *Louisiana Power and Light Company*, Opinion No. 110,¹²⁸ where the Commission was discussing expense lags it observed:

A fully developed lead-lag study must include a calculation of the lag in paying other operating and maintenance expenses based on an audit which is in turn based on an appropriate sampling methodology.

In *Louisiana Power and Light Company*,¹²⁹ the Commission was faced with a lead lag study where the other O&M expense lag was calculated by using the weighted average of the expense lags for fossil fuel, labor, and purchased power. The Commission, however, rejected this methodology because it was not based on an appropriate sampling methodology. In *Wisconsin Power and Light Company*,¹³⁰

¹²⁵ Commonwealth Edison Company, Opinion No. 165, 23 FERC ¶ 61,219 at 61,469 (1983).

¹²⁶ 6 FERC ¶ 61,154 at 61,296 (1979).

¹²⁷ 12 FERC at 61,080.

¹²⁸ 14 FERC at 61,122.

¹²⁹ 14 FERC at 61,122.

¹³⁰ Opinion No. 141, 19 FERC ¶ 61,288 (1982), *affirming*, Initial Decision, 12 FERC ¶ 63,059 at 65,243-4 (1980).

however, the Commission approved an ALJ's adoption of a lead lag study where no separate audit of the other O&M expense category was performed. A net 45 day lag was used and it was accepted because the record showed the number was conservative.

Each lead-lag study should contain a category involving tax payment lags. In *Southern California Edison Company*, Opinion No. 145¹³¹ the Commission stated:

The object of the income tax component of a cash working capital allowance is to reflect income taxes payable. Ratably flowed-through ITCS (other than in the year incurred) are in the nature of bookkeeping entries and thus 'non-cash' items. They do not affect the payment due the IRS and should not be reflected in the cash working capital allowance.

Another issue that has arisen in the connection with the development of the revenue lag is the length of time for bill preparation. In *Virginia Electric and Power Co.*,¹³² the intervenors' witness shortened the bill preparation time from VEPCO's actual 15 day period to seven days. The ALJ rejection of this adjustment was affirmed by the Commission in Opinion No. 118.¹³³ In *Commonwealth Edison Company*, Opinion No. 165,¹³⁴ the Commission stated that:

The 30 day bill preparation period, on the other hand, was designed entirely by Commonwealth. Were we to invoke the modified formula in this proceeding, it would have been incumbent upon the company to demonstrate the reasonableness of this period since it would be inequitable to burden the ratepayers with an unreasonable bill preparation period which results solely from the company's billing practices. Commonwealth has not, however, explained why such a lengthy period was necessary to read the meters and to compute the bills. Our experience with other utilities convinces us that 30 days is considerably more than industry norms. Commonwealth failed to demonstrate special circumstances on its system which requires a greater bill preparation period than the industry norm and thus we find its proposed working capital allowance unsupported by the record.

Utilities have attempted to include non-cash items in lead lag studies at a zero days lag, which increased the total cash working capital allowance. These non-cash items include depreciation, amortizations of various items, insurance premiums, pensions, etc. The Commission has rejected the inclusion of these items in a lead lag study.¹³⁵ The rationale is set out in the *Southern California Edison* initial decision that was subsequently approved by the Commission in Opinion No. 62.¹³⁶

The Commission also has rejected inclusion of funds associated with interest payments on long-term debt and dividend payments on preferred and common stock. As stated in *Louisiana Power*:¹³⁷

First, the lead-lag study has reduced the lag in paying operating and maintenance expenses to reflect the availability of funds to pay interest on long-term debt and dividends on preferred and common stock.

¹³¹ 20 FERC ¶ 61,301 at 61,591 (1982).

¹³² 11 FERC at 65,157.

¹³³ 15 FERC at 61,106-7.

¹³⁴ 23 FERC at 61,467-8 (footnote omitted); accord, *Southern California Edison*, 8 FERC at 61,679.

¹³⁵ See *Southern California Edison Company*, Opinion No. 55, 8 FERC at 61,377; *Southern California Edison Company*, Initial Decision, 3 FERC at 65,209 (1978), affirmed, Opinion No. 62, 8 FERC at 61,678-9 (1979), affirmed, *Anaheim v. FERC*, 669 F.2d 799 (D.C. Cir. 1981); *Virginia Electric Power Company*, 11 FERC at 65,161.

¹³⁶ 3 FERC at 65,209.

¹³⁷ 14 FERC at 61,122 (citation omitted).

[T]he Commission rejected the use of interest on long-term debt in determining a utility's cash working capital allowance on the ground that such interest is not an operating or cost-of-service expense but a below-the-line item. The Commission reasoned that as a matter of policy these funds belonged to the utility and its shareholders to use them as working capital without remuneration. The same reasoning applies to funds used to pay dividends on preferred and common stock.

b. Negative cash working capital allowances

The Commission has not imposed upon an electric utility a negative cash working capital allowance. In the three cases where it faced this issue, the Commission chose to give the utility a zero cash working capital allowance. In *Public Service Company of New Mexico*, Opinion No. 146,¹³⁸ the Commission in rejecting a negative cash working capital allowance stated:

The question before us is whether a negative figure resulting from what the ALJ found to be a fully developed and reliable lead-lag study should be deducted from the working capital component of rate base. This question has never come before the Commission, nor is it clear that such a situation was even contemplated in Opinion No. 19-A or the proposed rulemaking. Although we do not adopt the judge's or staff's rationale for holding the CWCA figure at zero, we are persuaded that a rate base deduction should not be made without further analysis and careful consideration of the matter. Furthermore, because of the minor monetary impact of this issue, we find that the rates will be just and reasonable regardless of whether the rate base deduction is made. We, therefore, order a CWCA of zero for the purposes of this case.

In *Minnesota Power and Light Company*, Opinion No. 155,¹³⁹ and *Public Service Company of New Mexico*, Opinion No. 164,¹⁴⁰ the Commission adopted the rationale set out in Opinion No. 146 in rejecting negative cash working capital allowances.

c. Fuel Stock

Fuel stockpile should be sufficient to allow the utility to operate its plants at their rated capacity without interruption due to lack of fuel. The coal stock is included in rate base because the ratepayers will not be charged for the fuel until after it is burned. The amount of fuel stock that a utility reasonably needs is an issue that is sometimes litigated.

In *Wisconsin Power and Light Company*,¹⁴¹ the company proposed a coal inventory of 100 days at one unit and 125 days for the remainder of its plants. Relying on statements made by the Company that it attempts to maintain a 45-90 day coal inventory, the ALJ reduced the coal stock to 90 days. The Commission in Opinion No. 141 affirmed the ALJ on this issue.¹⁴²

In *Kansas Gas and Electric Company*,¹⁴³ the company proposed an average coal supply of 183 days and average oil supply of 200 days. The intervenors proposed 90 days for coal and 190 days for oil. The ALJ held that a 90 day supply of coal and a 190 day supply of oil were reasonable.¹⁴⁴ This decision was based primarily on the fact that a 90 day coal stock and 190 day oil stock were consistent with KG&E's past practices, and KG&E was unable to show that any changed circumstances justified

¹³⁸ 20 FERC at 61,550-1.

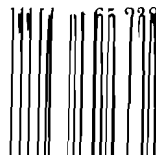
¹³⁹ 21 FERC ¶ 61,233 at 61,520-1 (1982).

¹⁴⁰ 23 FERC ¶ 61,218 at 61,457 (1983).

¹⁴¹ Opinion No. 141, 19 FERC ¶ 61,288 (1982) (affirming 12 FERC ¶ 63,059 (1981)).

¹⁴² *Id.* at 61,566.

¹⁴³ Initial Decision, 7 FERC ¶ 63,051 at 65,236-9 (1979).



different numbers.¹⁴⁵ In *Carolina Power and Light Company*, the Company's fuel stock was reduced:

Utilizing CP&L's own target and budget figures Witness Saffer reduced CP&L's total figure of \$57,732,510 by \$6,604,471 to an allowable figure of \$51,128,039. It was further noted that the target coal stock represents an 89.5 day coal pile and that CP&L considers its coal stock as of June 30, 1975 and June 30, 1976, of 63 and 84 days respectively, to be sufficient.¹⁴⁶

The Commission in Opinion No. 19¹⁴⁷ affirmed the ALJ on this issue. In the two subsequent *Carolina Power and Light* cases, the ALJs found that a 75 day coal stock was reasonable.¹⁴⁸

B. Construction Work in Progress (CWIP)

I. Order No. 298

Generally, only facilities which are used and useful are allowed to be included in a utility's rate base. The FPC in Order No. 555¹⁴⁹ and FERC in Order No. 298¹⁵⁰ created exceptions to the used and useful rule for CWIP. In Order No. 555 the Commission allowed the inclusion of pollution control and fuel conversion CWIP in rate base, while also establishing a mechanism to allow additional CWIP in rate base upon a finding of severe financial distress.

Order No. 298 allows a utility to include in rate base "up to 50 percent of all CWIP in excess of that actually included in rate base as pollution control or fuel conversion facilities, regardless of the utility's financial condition."¹⁵¹ CWIP includes both the expenditure in the construction project and accrued AFUDC.¹⁵²

The amount of CWIP to be allowed in rate base is subject to a number of limitations. For example, in the first two years after the effective date of the rates, a utility cannot include CWIP that would be more than six percent of the test period aggregate wholesale revenues under the rate schedules that were superceded.¹⁵³ Moreover, if a utility receives CWIP in the first year, it must allow those CWIP rates to remain in effect for at least 10 months.¹⁵⁴ Thus the maximum increase in rates resulting from CWIP that could occur in the first 20-24 months after the rule was issued is 12 percent. After two years, the utility is allowed to receive 50 percent CWIP regardless of the impact. CWIP will not automatically be allowed to be included in rate base. As the Commission stated in Order No. 298:

The final rule adopted will fundamentally reorient the Commission's assessment of the reasonableness of construction programs. It affords in effect an opportunity to review and judge the prudence of costs as those costs are incurred and claimed in rate base, rather than

¹⁴⁵*Id.* at 65,237-39. See also Opinion No. 80, 10 FERC ¶ 61,243 at 61,461 (1980).

¹⁴⁶4 FERC at 65,139.7

¹⁴⁷4 FERC ¶ 61,107 at 61,224. It appears that in *Carolina Power* the Commission approved an 89.5 day coal stock allowance, but this is not entirely clear. In a subsequent *Carolina* case, all of the parties, including the company, agreed that the Commission in Opinion No. 19 adopted a 75 day coal supply. *Carolina Power and Light Company*, 17 FERC at 65,171 n.86 (1981).

¹⁴⁸See 9 FERC at 65,241-2 (1979); 17 FERC at 65,151.

¹⁴⁹Docket No. RM75-13 (November 8, 1976), *reh. denied*, Order No. 555-A (January 6, 1977).

¹⁵⁰See *supra* note 122.

¹⁵¹Order No. 298, mimeo at 144.

¹⁵²*Id.* mimeo at 145; 18 C.F.R. § 35.26(b).

¹⁵³18 C.F.R. § 35.26(d)(1)(i).

¹⁵⁴18 C.F.R. § 35.26(d)(1)(ii).

at a later point in time when a project is completed or abandoned and a potentially unwise investment has already been made.¹⁵⁵

2. Pollution Control CWIP

The leading case on whether a pollution control facility can be included as rate base is *Louisiana Power and Light Company*, Opinion No. 110.¹⁵⁶ The Commission, after a lengthy analysis held that radiation control facilities are not "pollution control facilities."¹⁵⁷ The Commission also rejected the inclusion in rate base of facilities used to control pollution during construction because "they are basically normal construction costs."¹⁵⁸ Plant structures used to house pollution control facilities were found not to be "pollution control facilities."¹⁵⁹ In *Louisiana Power*, the Commission did allow certain facilities to be included as pollution control CWIP, including:

- (1) systems for the treatment of sanitary waste;
- (2) chemical treatment systems and oil separation systems for non-radioactive liquid wastes;
- (3) air and water monitoring systems; and
- (4) cooling water intake and discharge structures (except for a radiological monitoring system).¹⁷⁶

C. Use of Thirteen Monthly Balances

Utilities generally add to their rate base over time, so that the rate base value at the end of the test year is larger than the beginning rate base value. The Commission has stated that, unless facts or circumstances warranting departure from an average rate base must be used.¹⁶¹ Indeed, an average rate base is used "except in extraordinary circumstances."¹⁶² Two averaging techniques have been used: thirteen monthly balances or the average of beginning and ending balances. Of these two approaches the use of thirteen monthly balances has been most favored and adopted in numerous proceedings.¹⁶³

D. AFUDC

1. Net vs. Gross AFUDC

The Commission policy on gross vs. net AFUDC (allowance for funds used during construction)¹⁶⁴ rates is set out in *Kentucky Utilities Company*, Opinion No. 184:

¹⁵⁵ Mimeo at 92.

¹⁵⁶ 14 FERC ¶ 61,075 (1981).

¹⁵⁷ *Id.* at 61,113-6.

¹⁵⁸ *Id.* at 61,116.

¹⁵⁹ *Id.* at 61,117.

¹⁶⁰ *Id.* at 61,112, 61,116.

¹⁶¹ *Alabama Power Company*, Opinion No. 54, 8 FERC at 61,331; *Southwestern Public Service Company*, Initial Decision, 18 FERC ¶ 63,007 at 65,040 (1982), *affirmed*, Opinion No. 162, 22 FERC ¶ 61,341 (1983); *Lockhart Power Company*, Opinion No. 29, 4 FERC ¶ 61,337 at 61,802 (1978).

¹⁶² *Public Service Company of Indiana*, Opinion No. 783-A, 57 F.P.C. at 1186 (1977); *Southwestern*, 18 FERC at 65,040.

¹⁶³ *Southwestern*, 18 FERC at 65,040-1; *Illinois Power Company*, Initial Decision, 11 FERC ¶ 63,040 at 65,253 (1980), *affirmed*, 15 FERC ¶ 61,050 (1981); *Minnesota Power and Light Company*, Opinion No. 20, 4 FERC ¶ 61,116 at 61,267 (1978); *see Louisiana Power and Light Company*, Opinion No. 110, 14 FERC ¶ 61,075 at 61,117-8 (1981) (13 monthly balances used for CWIP).

¹⁶⁴ AFUDC regulations were promulgated by Order No. 561, 57 F.P.C. 608 (1977), *reh. denied and clarified*, Order No. 561-A, 59 F.P.C. 1340 (1977).

Our current policy requires AFUDC to be computed with the gross-of-tax method unless some other regulatory agency having jurisdiction over the company involved requires the net-of-tax method.¹⁶⁵

Consider the situation in which the plant goes into service before it is included in rate base. In a recent proceeding, the utility argued that AFUDC could be accrued on the plant until the rates including that plant in rate base became effective.¹⁶⁶ The ALJ held that no AFUDC could be accrued on that plant once it went into service regardless of when the rates took effect. The Commission affirmed the initial decision.¹⁶⁷

The other issue that arises is similar. That is for CWIP included in rate base, does AFUDC stop accruing when the CWIP is included in the test period or when the rates take effect? This issue was concluded in two initial decisions where the ALJs held that AFUDC should stop accruing when the plant is included in the test period.¹⁶⁸ Both cases were settled before a Commission decision was issued.

The Commission, did, however, deal with this issue in the new CWIP rule. In the rule, the Commission stated that AFUDC accruals will cease on the proposed effective date of the rates for the purpose of establishing rates in that case.¹⁶⁹ For future cases the AFUDC accruals would track the effective date of the rates.¹⁷⁰

VI. RATE OF RETURN

A. Return on Equity

1. Discounted Cash Flow Method

The Commission in carrying out the mandate of *Bluefield*,¹⁷¹ has expressed a preference for forward-looking, market-oriented analyses, particularly the discounted cash flow (DCF) method.¹⁷² Indeed, in one case the Commission established a return on equity through the use of a DCF analysis even though none of the parties to that proceeding used a DCF analysis.¹⁷³

The basic DCF formula is as follows:

$$K = \frac{D}{P} + g$$

K = Return on equity
 D = Dividend/share
 P = Stock price
 g = Growth factor

¹⁶⁵ 24 FERC ¶ 61,158 at 61,362-3 (1983); *accord*, Southern California Edison, 20 FERC at 61,586-7.

¹⁶⁶ Kentucky Utilities Company, Initial Decision, 24 FERC ¶ 63,045 (1983).

¹⁶⁷ Kentucky Utilities Company, 25 FERC ¶ ____ (issued November 18, 1983).

¹⁶⁸ Indiana and Michigan Electric Company, 11 FERC ¶ 63,037 at 65,228-9 (1980); Carolina Power and Light Company, 17 FERC at 65,153.

¹⁶⁹ Order 298, mimeo at 149 n.109.

¹⁷⁰ *Id.*

¹⁷¹ *Bluefield Water Works v. Public Service Comm'n.*, 262 U.S. 679, 692-93 (1923); *F.P.C. v. Hope Natural Gas Co.* 320 U.S. 591, 605 (1944).

¹⁷² Central Illinois Light Company, Opinion No. 81, 10 FERC ¶ 61,248 at 61,480 (1980); Minnesota Power & Light Company, Opinion No. 12, 3 FERC ¶ 61,045 at 61,132-3 (1978); Connecticut Yankee Atomic Power Company, Opinion No. 148, 20 FERC ¶ 61,373 at 61,767 (1982); New England Power Company, Opinion No. 158, 22 FERC ¶ 61,123 at 61,187 (1983).

¹⁷³ Minnesota Power & Light Co., Opinion No. 20, 4 FERC ¶ 61,116 at 61,264-6 (1978). *See also* Consolidated Gas Supply Corporation, Opinion No. 180, 24 FERC ¶ 61,046 at 61,145-7 (1983).

"D/P" is commonly referred to as the dividend yield.

The Commission has set out certain standards for calculating the dividend yield. First, the most current data in the record should be used.¹⁷⁴ Second, spot yields should not be used because their use could lead to aberrational results. Dividend yields from a number of months of data should be used.¹⁷⁵ Third, the dividend and stock price should be from the same period.¹⁷⁶ Fourth, the dividend yield should be adjusted to reflect the fact that dividends are paid on a quarterly basis. If dividends are assumed to be paid continuously, the dividend yield is D/P. This is called the continuous model. If dividends are assumed to be paid annually and to grow at a constant rate, the dividend yield is calculated as $D(1+G)/P$ where "G" is equal to the DCF growth factor. This is the discrete model. Because dividends are paid on a quarterly basis, the Commission has repeatedly stated that the proper model would produce a result somewhere between these two models,¹⁷⁷ and consequently the Commission has averaged the results of the continuous and discrete models.¹⁷⁸

The key to a DCF analysis is the determination of a growth factor or G value. In determining this growth factor, the Commission has stated that it seeks "thoughtful" and "well supported" estimates.¹⁷⁹ In satisfying this standard, a number of requirements need to be met. First, the growth factor must be forward-looking. That is — the analyst cannot rely on a simple extrapolation of historical data without considering whether the historical trend will be indicative of what will occur in the future.¹⁸⁰ Second, one of the primary factors looked at should be book value growth.¹⁸¹ This can be done through the use of the following formula:

$$\begin{aligned}
 g &= br + sv \\
 b &= \text{retention ratio} \\
 r &= \text{earned return on equity} \\
 s &= \text{amount of new stock issuances} \\
 v &= 1 - \frac{1}{\text{market to book ratio}}
 \end{aligned}$$

This formula is consistent with *Public Service Company of Indiana*, Opinion No. 44,¹⁸² and has been used in deriving returns on equity accepted by the Commission.¹⁸³

¹⁷⁴New England Power Company, Opinion No. 158, 22 FERC at 61,187.

¹⁷⁵*Id.*; Consolidated Gas Supply Corp., Opinion No. 180, 24 FERC ¶ 61,046 at 61,145-6; Minnesota Power & Light Company, Opinion No. 86, 11 FERC ¶ 61,312 at 61,640 (1980); New England Power Company, Opinion No. 49, 8 FERC ¶ 61,054 at 61,171 (1979).

¹⁷⁶22 FERC at 61,188.

¹⁷⁷*Id.*; Consolidated Gas, 24 FERC at 61,145-6; Minnesota Power, Opinion No. 86, 11 FERC at 61,640; Public Service Company of Indiana, Opinion No. 44, 7 FERC ¶ 61,319 at 61,709 (1979); Minnesota Power and Light Company, Opinion No. 20, 4 FERC ¶ 61,116 at 61,265 (1978); Minnesota Power and Light Company, Opinion No. 12, 3 FERC ¶ 61,045 at 61,143, n.9 (1978).

¹⁷⁸Consolidated Gas, 24 FERC at 61,146, 61,151.

¹⁷⁹Central Illinois Light Company, Opinion No. 81, 10 FERC at 61,480.

¹⁸⁰Middle South Services, Inc., Opinion No. 124, 16 FERC ¶ 61,101 at 61,222 (1981); CILCO, Opinion No. 81, 10 FERC at 61,480.

¹⁸¹New England Power Co., 22 FERC at 61,188.

¹⁸²7 FERC at 61,708.

¹⁸³Delmarva Power & Light Company, Initial Decision, 17 FERC ¶ 63,044 at 65,222, 65,225 (1981), *affirmed*, Opinion No. 185, 24 FERC ¶ 61,199 (1983); Kansas City Power & Light Company, Initial Decision, 21 FERC ¶ 63,007 at 65,017, *affirmed*, 22 FERC ¶ 61,262 (1983); Public Service Company of New Mexico, Initial Decision, 18 FERC ¶ 63,005 at 65,016 (1982), *affirmed*, Opinion No. 146, 20 FERC ¶ 61,290 (1982).

B. Capital Structure

1. Choice of capital structure

An independent utility which issues its own stock and bonds will use its own capital structure in deriving the overall return. Problems arise where the utility is a subsidiary of another company.¹⁸⁴ In choosing a capital structure in that situation, the Commission has established certain standards. In *Consolidated Gas Supply Corporation*, Opinion No. 180 it stated:¹⁸⁵

We reaffirm our policy, set forth in *Kentucky West Virginia Gas Co.* [Opinion No. 7], concerning the use of an imputed capital structure for a jurisdictional subsidiary whose parent provides all or part of its capital. The subsidiary's capital structure can be used only after a showing that it reasonably reflects the risks of the subsidiary. The consolidated capitalization can be used only where there is a showing that the parent and the subsidiary have essentially the same business risks. But where their business risks significantly differ, a hypothetical capitalization must be developed based on the average capital structure of comparable firms that obtain their own financing.

2. Undistributed subsidiary earnings

The Commission has stated that undistributed subsidiary earnings which are included in Account 216.1 cannot be included in the equity component of the parent's capital structure.¹⁸⁶ The Commission has stated:

We do, however, adhere to the basic proposition that undistributed subsidiary earnings must be excluded from the . . . [utility's] capitalization for rate of return purposes. We take this position for the reason that the rate of return capitalization should, as nearly as possible, be representative of the types and relative amounts of capital invested in the company's rate base to which the rate of return is applied. Since undistributed subsidiary earnings are not available to the pipeline for purposes of rate base investment and since the rate base therefore does not include investments which can be attributed to undistributed subsidiary earnings, those earnings must be excluded from the capitalization. Distributed subsidiary earnings, conversely, are available to the pipeline for rate base investment (or retirement of debts previously used for rate base investment) and are therefore properly includable in capitalization.¹⁸⁷

3. Equity exclusion

Another issue that arises is whether the parent's investment in a subsidiary should be excluded from the equity component of the parent company's capital structure. In *New England Power Company*, Opinion No. 49, the Commission was faced with the question of what to do with NEP's investment in the four Yankee companies, which are single asset nuclear utilities. The Commission held that

¹⁸⁴ Another capital structure issue is that of double-leveraging. In *Philadelphia Electric Power Company*, Opinion No. 197, 25 FERC ¶ 61,165 (1983), the Commission adopted a double-leveraging adjustment.

¹⁸⁵ 24 FERC at 61,134-5 (footnote omitted). Hypothetical capital structures have been adopted in *Consolidated*, Opinion No. 180; and *Indiana and Michigan Power Company*, Opinion No. 27, 4 FERC ¶ 61,316 at 61,739 (1978).

¹⁸⁶ *United Gas Pipe Line Company*, Opinion No. 99, 13 FERC ¶ 61,044 at 61,096 (1980); *Philadelphia Electric Company*, Initial Decision, 10 FERC at 65,359, *affirmed*, 13 FERC ¶ 61,057 (1980); *Indiana & Michigan Electric Company*, Initial Decision, 4 FERC ¶ 63,039 at 65,312 (1978), *affirmed*, Opinion No. 79, 10 FERC ¶ 61,237 (1980); Order No. 469, 49 FPC 326 (1973).

¹⁸⁷ *United Gas*, *supra* at 13 FERC at 61,096.

NEP's investment in the Yankee companies should be excluded from the common equity portion of NEP's capital structure.¹⁸⁸

In *Philadelphia Electric Company*,¹⁸⁹ the Commission refused to deduct the parent's investment in its subsidiary from the equity portion of its capital structure:

Here we are concerned with only the parent-subsidiary relationship. PE finances its consolidated operations as a unified whole. Its reports to investors are prepared on a consolidated basis. In addition, its subsidiary earnings provide coverage on the debt and the preferred stock issued by PE. Finally, its subsidiary asserts [sic] support the financial structure of the Philadelphia Electric System, *e.g.* PE has pledged its ownership in one of its subsidiaries, Philadelphia Electric Power Company, to the Trustees as additional security for its First and Refunding mortgage bonds.

We conclude that PE's financial relationships with its subsidiaries are substantially different from relationships involved in Yankee projects.

VII. FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION

A. *Functionalization*

With respect to general plant expenses, the Commission has stated that general plant will be functionalized by labor ratios unless it is shown that the use of labor ratios produces unreasonable results.¹⁹⁰ Labor ratios have been used to functionalize general plant in most, if not all, recent cases where the issue has been litigated.¹⁹¹

The Commission has also held that most A&G expenses are to be functionalized on the basis of labor ratios.¹⁹² An exception to this has been established for property insurance, which is functionalized on plant ratios.¹⁹³ Common plant and intangible plant have been analogized to general plant and functionalized on the basis of labor ratios.¹⁹⁴

B. *Classification*

After functionalizing, the next step is to classify those expenses as either demand, energy, or customer-related. The classification issue most frequently litigated is: whether the predominance method should be used. Staff for a number of years has used a method called the predominance method for classifying production O&M accounts. Under this method, if an account is *predominantly* energy-related, it will be classified as energy. The same is also true with respect to

¹⁸⁸ 8 FERC at 61,172-74.

¹⁸⁹ 13 FERC at 61,116-17; *accord*, Southern California Edison Company, Opinion No. 62, 8 FERC ¶ 61,198 (1979), *affirming*, Initial Decision, 3 FERC ¶ 63,033 at 65,203 (1978); Indiana & Michigan Electric Company, Opinion No. 79, 10 FERC ¶ 61,237, *affirming*, Initial Decision, 4 FERC at 65,312.

¹⁹⁰ Minnesota Power and Light Company, Opinion No. 20, 4 FERC at 61,268.

¹⁹¹ *See, e.g.*, Kansas City, Initial Decision, 21 FERC at 65,034 (1982), *affirmed*, 22 FERC ¶ 61,262 (1983); Delmarva, Initial Decision, 17 FERC ¶ 63,044 at 65,204 (1981), *affirmed*, Opinion No. 185, 24 FERC ¶ 61,199 (1983); Philadelphia Electric Company, Initial Decision, 10 FERC ¶ 63,034 at 65,355-6 (1980), *affirmed*, 13 FERC ¶ 61,057 (1980).

¹⁹² Missouri Power & Light Company, Opinion No. 31, 5 FERC ¶ 61,086 at 61,137-8 (1978); Kansas City, 21 FERC at 65,035; Delmarva Power and Light Company, 17 FERC at 65,204.

¹⁹³ Pacific Gas & Electric Company, Initial Decision, 16 FERC ¶ 63,004 at 65,015-16 (1981), *affirmed*, Opinion No. 147, 20 FERC ¶ 61,340 (1982); Kansas-Nebraska Natural Gas Company, Opinion No. 731, 53 F.P.C. 1691, 1722 (1975).

¹⁹⁴ Kansas City Power and Light Company, 21 FERC at 65,035; Delmarva Power and Light Company, 17 FERC at 65,204; Philadelphia Electric Company, 10 FERC at 65,355-6.

demand related costs. This method has been repeatedly adopted by the Commission.¹⁹⁵

C. Allocation

The allocation of demand costs is a complex and often litigated issue. Issues that are usually litigated include: (1) which coincident peak (CP) demand allocation method (1 CP, 3 CP, 4 CP, or 12 CP) should be adopted; (2) whether the numerator (CP's) and/or the denominator (total system demands) in the demand allocator have been properly projected; and (3) whether transmission costs should be rolled-in and allocated on the same basis.¹⁹⁶

Demand costs are generally allocated in proportion to a customer's load coincident with the system peak load. The four CP methods which have been accepted in cases at the Commission are 1 CP, 3 CP, 4 CP, and 12 CP. Under a 1 CP method, the allocator for a particular wholesale class will be the wholesale class' CP demands for the sytem's peak month divided by the total company system peak.¹⁹⁷ Similarly, for 3, 4 and 12 CP companies the numerator would consist of the average of the wholesale class' coincident peaks for each of 3, 4 or 12 months while the denominator would consist of the average of the total system peaks for each of the months.

The Commission has not established a policy for determining which allocation method is appropriate but has set out certain factors which must be considered:¹⁹⁸

[T]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales.

If a utility's system demand curve is relatively flat, then that would support the use of a 12 CP method. If a utility experiences a pronounced peak during one, three, or four consecutive months, then that would justify the use of a 1, 3, or 4 CP method, respectively.

In determining whether a utility experiences a pronounced peak during a particular time period, a number of tests are used. First, the average of the sytem peaks during the purported peak period as a percentage of the annual peak should be compared to the average of the system peaks during the off-peak months as a percentage of the annual peak. Large differences between these two figures lends

¹⁹⁵ See e.g., Arizona Public Service Company, 4 FERC ¶ 61,101 at 61,209-10 (1978); Illinois Power Company, Initial Decision, 11 FERC ¶ 63,040 at 65,255-6 (1980), *affirmed*, 15 FERC ¶ 61,050 at 61,093 (1981); Kansas City, Initial Decision, 21 FERC ¶ 63,003 at 65,037 (1982), *affirmed*, 23 FERC ¶ 61,262 (1983); Minnesota Power & Light Company, Opinion No. 86, 11 FERC ¶ 61,312 at 61,648-9 (1980).

¹⁹⁶ Numerous terms of art are used in discussing allocation issues. The terms are (1) coincident peak (CP) demands, which are the demands of a particular customer or class occurring at the time of the system peak for a particular time period; (2) noncoincident peak (NCP) demands which are the maximum demands of a particular customer or class for a particular time period; (3) coincidence factor (CF), which is equal to CP's dividend by NCP's; (4) diversity factor, which is the inverse of a CF; and (5) load factor, which is equal to the Kwh's for a particular period divided by the product of the maximum demand or Kw multiplied by the number of hours in that period.

¹⁹⁷ Since the CP demands are measured at the customer's meter and the total system demands are measured at the generating plants, it is necessary to increase the CP demands to account for losses.

¹⁹⁸ Carolina Power & Light Company, Opinion No. 19, 4 FERC at 61,230 (1978); Commonwealth Edison Company, 15 FERC ¶ 63,048 at 65,196 (1981), *affirmed*, Opinion No. 165, 23 FERC ¶ 61,219 (1983); Illinois Power Company, 11 FERC at 65,247-8 (1980), *affirmed*, 15 FERC ¶ 61,050 (1981).

support to using something other than a 12 CP method while a smaller difference supports 12 CP.¹⁹⁹

A second test used has been to look at the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP and vice-versa.²⁰⁰

Another test is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Company*, Opinion No. 19,²⁰¹ the Commission adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Company*,²⁰² a 4 CP method was adopted where over a four year period, a peak in one of the 4 peak months was only exceeded once by a peak from a non-peak month.

Another test is the average of the twelve monthly peaks as a percentage of the highest monthly peak.²⁰³ To the extent a utility uses the off-peak months to perform its scheduled maintenance, that supports the use of 12 CP.²⁰⁴ However, the scheduled maintenance must be considered together with the reserves available after the maintenance. To the extent the reserve margins are fairly stable after maintenance, then a 12 CP method is supported. If the reserve margins drop substantially to marginal levels during certain months, then a method other than 12 CP may be supported.²⁰⁵

The Commission has in some cases accepted CP estimates based on multiple years data rather than an estimate based on one year.²⁰⁶ The Commission has, however, also adopted CP projections based on the use of one year's data.²⁰⁷

VIII. RATE DESIGN

Two rate design issues have arisen in numerous uses: (1) whether particular customers should be in a particular class; and (2) whether a ratchet should be imposed.²⁰⁸

¹⁹⁹See, e.g., *Louisiana Light & Power Co.*, Opinion No. 813, 59 F.P.C. 968 (1977); *Louisiana Power & Light*, Opinion No. 110, 14 FERC ¶ 61,075 (1981); *Commonwealth Edison Co.*, 15 FERC at 65,196.

²⁰⁰See, e.g., *Louisiana*, *supra*, note 99.

²⁰¹4 FERC at 61,229.

²⁰²15 FERC at 65,198.

²⁰³See *supra* note 200.

²⁰⁴*Alabama Power Company*, Opinion No. 54, 8 FERC ¶ 61,083 at 61,327 (1979); *Illinois Power Company*, 11 FERC at 65,249; *New England Power Company*, Opinion No. 803, 58 F.P.C. 2322, 2338 (1977); *but see* *Commonwealth Edison*, 15 FERC at 65,199.

²⁰⁵See *Illinois Power Co.*, 11 FERC at 65,249 (46 percent for 8 non-summer months and 34.5 percent for summer months — 12 CP); *Commonwealth Edison Co.*, 15 FERC ¶ 63,048 for 1979 36.63 percent for 8 non-summer months and 22.15 percent for 4 summer months — 4 CP).

²⁰⁶See, e.g., *Otter Tail Power Company*, Opinion No. 93, 12 FERC ¶ 61,169 at 61,429 (1980); *Commonwealth Edison Co.*, Initial Decision, 15 FERC at 65,190, *affirmed*, Opinion No. 165, 23 FERC ¶ 61,219 (1983) (3 yrs. average adopted).

²⁰⁷*Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

²⁰⁸Other rate design issues have arisen and have been resolved by the Commission. These issues are: (1) rate tilts, which the Commission has usually rejected (*Idaho Power Company*, Opinion No. 13, 13 FERC at 61,299; *Minnesota Power and Light Co.*, Opinion No. 12, 3 FERC at 61,141-2; (2) marginal cost pricing, which the Commission accepted for the first time in *Wisconsin Electric Power Company*, Opinion No. 186, 24 FERC ¶ 61,299 at 61,638 (1983); (3) time-of-day rates, which have been accepted in *Wisconsin Electric Power Company*, 24 FERC at 61,637-8 and in *Commonwealth Edison Co.*, Opinion No. 165, 23 FERC ¶ 61,219, *affirming*, 15 FERC at 65,239-40; and (4) declining block energy rates, which were rejected in *Commonwealth Edison Company*, 3 FERC at 65,147, *affirmed*, Opinion No. 63, 8 FERC at 61,844 and in *Central Illinois Light Company*, 6 FERC at 65,130, *affirmed*, Opinion No. 81, 10 FERC ¶ 61,248.

A. Customer Classification

In *Central Illinois Public Service Company*, Opinion No. 142 it was stated:

Most electric utilities serving numbers of wholesale customers divide their customers into convenient, logical groups for rate determining purposes. Normally these classifications are rooted in historical practice and are not controversial. Classifications may be based on voltage level, relative size of the load being served, partial versus full requirement service, or other similar criteria. One of the most widely used and accepted classifications is that between cooperative and municipal customers in the case of utilities serving both types of customers.²⁰⁹

In determining whether a utility's customer classification should be changed, the Commission in *Kentucky Utilities Company*, Opinion No. 184, set out the following test:²¹⁰

[A]re the wholesale customers sufficiently dissimilar to warrant their placement in separate rate classes? . . . In applying this test, we do not limit our consideration to any particular factor or group of factors.²¹¹

In discussing customer classification criteria, the Commission in *Central Illinois Public Service Co.*²¹² also stated:

The matter of classification is not an exact science, and it should be considered from the standpoint not only of load factor and other cost-causing characteristics, but also from the standpoint of practicality and common sense.

Thus the Commission has stated that no one factor is dispositive on this issue. Nonetheless, cost information such as load factor and coincidence (or diversity) factor data should be considered in every case where this issue arises.²¹³

B. Ratchets

A ratchet imposes minimum payment obligations on utility customers. Two determinative factors in deciding whether a ratchet should be allowed are whether the customer is a full requirements customer, and whether the demand costs are allocated on a 12 CP basis. If the customer is a full requirements customer and if the demand costs are allocated on a 12 CP basis, then the ratchet generally will be disallowed.

In *Central Illinois Light Company*, Opinion No. 81,²¹⁴ the Commission stated that:

On the contrary, certain logical gaps in the company's presentation suffice to reinforce our impression that use of a demand billing ratchet is generally an unnecessary means of mirroring actual or imputed customer causation of incurred capacity costs when the 12-CP demand allocation method has been found appropriate for allocation of class costs or, as here, when its use is uncontested. We note that one important working assumption of the

²⁰⁹20 FERC 61,043 at 61,085 (1982); see *Southern California Edison Company*, Opinion No. 145, 20 FERC ¶ 61,301 (1982); *Delmarva Power and Light Company*, 22 FERC ¶ 63,052, *affirmed*, Opinion No. 189.

²¹⁰24 FERC ¶ 61,158 at 61,362 (1983) (citation omitted).

²¹¹See 20 FERC at 61,594.

²¹²20 FERC at 61,086.

²¹³See, e.g., *El Paso Electric Company*, Opinion No. 109, 14 FERC ¶ 61,082 (1981), *affirming*, Initial Decision, 10 FERC ¶ 63,008 at 65,034-5 (1980); *St. Michaels Utilities Commission v. Eastern Shore Public Service Company of Maryland*, Initial Decision, 35 F.P.C. 605, 619 (1965), *affirmed*, 35 F.P.C. 591, 595 (1966), *affirmed*, *St. Michaels Utilities Commission v. FPC*, 377 F.2d 912, 915-6 (D.C. Cir. 1967).

²¹⁴10 FERC at 61,474-5 (footnote omitted).

12-month average coincident peak method of allocation is that actual demands of the respective customers in *each* on the months contribute to system coincident peak demand or, in other words, result in actual cost causation, and to a roughly uniform degree from month to month. We find this assumption reasonable in this case, and believe that a given individual customer's monthly 12-CP demand allocating factor is generally in itself, without imposition of the added ratchet, also the most appropriate basis for deriving its demand charge billing determinant.

For these reasons we believe that where, as here, the 12-CP method of demand allocation has been well-chosen — for example, because of a relatively "level" or "flat" monthly system-wide demand pattern — the applicant utility must bear the burden of demonstrating that the ensuing disadvantages to consumers of an additionally imposed demand ratchet are *outweighed* by any benefits to be derived by the utility itself, or by the consuming public. Insofar as this proceeding is concerned, we conclude that CILCO has not met its burden of demonstrating the justness and reasonableness of its proposed ratchet, and that the initial decision of the presiding judge should therefore be reversed on this issue.

Any utility proposing the imposition of a ratchet on a full requirements customer where the utility uses a 12 CP demand allocation method has an especially heavy burden to meet.²¹⁵ In three recent cases, this Commission has approved ratchets for partial requirements customers where a 12 CP method was used.²¹⁶ In *Cleveland Electric* the Commission stated that:

The purpose of a ratchet is to insure that a utility has an opportunity to recover its projected demand costs and that customers bear their fair share of the demands placed on the system. The record shows that City's firm demand fluctuated considerably in the past. Because of City's ability to use alternate power sources and vary its demand on CEI's system, a 50 percent ratchet would provide a fair means of protecting CEI from load variations. The judge properly relied on Opinion Nos. 114 and 155, *supra*, in which we emphasized that a demand ratched in conjunction with 12 CP allocation may be appropriate where partial requirements customers are involved. This is because those customers have the ability to control their load by using alternative sources of capacity and the ratchet will compensate the utility for the capacity it must hold ready for the partial requirements customers should they choose to take it.²¹⁷

The Commission also has approved ratchets for full requirements customers where a demand allocation method other than 12 CP was used.²¹⁸

There does not appear to be any hard-and-fast rule respecting the level of an appropriate ratchet, though an examination of Commission cases does provide some

²¹⁵ See, e.g., *Delmarva*, 17 FERC ¶ 63,044 at 65,210, *affirmed*, Opinion No. 185, 24 FERC ¶ 61,199 (1983); *Central Illinois Public Service Company*, 14 FERC ¶ 63,048 at 65,146-7 (1981), *affirmed*, Opinion No. 142, 20 FERC ¶ 61,043 (1982); *Minnesota Power & Light Company*, Opinion No. 86, 11 FERC at 61,649-50; *Indiana & Michigan Electric Company*, Opinion No. 79, 10 FERC at 61,439; *Missouri Power & Light Company*, Opinion No. 31, 5 FERC at 61,139; *Carolina Power & Light Company*, Opinion No. 19, 4 FERC at 61,232.

²¹⁶ *Cleveland Electric Illuminating Company*, Opinion No. 172, 23 FERC ¶ 61,380 at 61,807 (1983); *Minnesota Power & Light Company*, Opinion No. 155, 21 FERC ¶ 61,233 at 61,522 (1982); *Connecticut Light and Power Company*, Opinion No. 114, 14 FERC ¶ 61,139 at 61,254 (1981), *affirmed*, Second Taxing District of the City of Norwall v. FERC, 683 F.2d 477 (D.C. Cir. 1982).

²¹⁷ 23 FERC at 61,807.

²¹⁸ See, e.g., *Commonwealth Edison Company*, Opinion No. 165, 23 FERC at 61,470-71 (4 CP); *Commonwealth Edison Company*, Opinion No. 63, 8 FERC at 61,844 (1 CP); *Louisiana Power & Light Company*, Opinion No. 110, 14 FERC at 61,129-30 (4 CP); *Carolina Power & Light Company*, Opinion No. 19, 4 FERC at 61,232-33 (1978) (4 CP).

guidance. With respect to cases where a 4 CP method has been used, the Commission has approved ratchets. For a 1 CP company, the Commission in *Commonwealth Edison Company*, Opinion No. 63,²¹⁹ has approved a 100 percent ratchet. For partial requirements customers where the company is using a 12 CP demand allocation method, the Commission also has approved the ratchets.²²⁰

IX. CONCLUSION

A large number of electric rate cases are set for hearing each year at FERC. The staff is able to handle adequately all of those cases because seventy to eighty percent of all cases settle. It is the author's hope that this article will aid the settlement process by serving as a guide to resolution of selected issues.

²¹⁹8 FERC ¶ 61,277 (1979).

²²⁰See cases cited *supra* note 216.