Endicott Pipeline Company
Initial Decision
55 FERC ¶ 63,028 (1991)

Endicott Pipeline Company (EPC) operates an interstate oil pipeline on the North Slope of Alaska. The Presiding Administrative Law Judge's (ALJ) Initial Decision was issued on May 28, 1991. It determined the justness and reasonableness of the proposed initial rate filing made by EPC with the Federal Energy Regulatory Commission (Commission). (Endicott Pipeline Company, 55 FERC ¶ 63,028 (1991)).

Two of the principle issues resolved by the ALJ were (1) his rejection of an automatic rate adjustment procedure known as the variable tariff methodology (VTM), which he stated could not be adopted due to the Commission's recent ruling on this issue in Kuparuk Transportation Company, 55 FERC ¶ 61,122 issued on April 25, 1991, (See also 55 FERC ¶ 63,028 at 65,139, 65,140), and (2) the rejection of trended original cost (TOC) ratemaking in favor of the more traditional depreciated original cost ratemaking incorporating a "unit of throughput" depreciation method. (Id. at 65,144-46). The Commission had previously invited alternative innovative solutions in any given case depending upon the circumstances of each case. (Id. at 65,141).

Concerning the VTM, the ALJ found that because EPC's rate base would probably continue to decline, a fixed initial rate would not be appropriate. The reasonable solution would be to set a variable initial rate. However, the ALJ concluded that the Commission lacked the statutory authority to approve a variable tariff. (Id. at 65,146). This was clearly determined in Kuparuk, supra.

Other major issues decided by the ALJ involved (1) overhead costs, (2) allowance for funds used during construction (AFUDC); (3) accumulated deferred income taxes (ADIT); (4) working capital allowance; (5) capital structure; (6) rates of return; (7) dismantling, removal and restoration (DR&R); and (8) actual throughput for 1988 to be used to determine the pipeline's "per-unit price or rate."

Endicott Pipeline Company,
Initial Decision
Determining Lawfulness of Oil
Pipelines Initial Rate
55 FERC ¶ 63,028 (1991).

[¶ 63,028]

Endicott Pipeline Company, Docket Nos. IS87-36-000 and IS87-36-001

Initial Decision Determining Lawfulness of Oil Pipeline's Proposed Initial Rate

(Issued May 28, 1991)

Raymond M. Zimmet, Presiding Administrative Law Judge.

Appearances

Frederick G. Wohlschlaeger, Philip R. Ehrenkranz, Keith R. McCrea, Alan P. Buchmann, James L. Trump, Paul F. Forshay, and *Julia R. Johnson* for Endicott Pipeline Company.

Edward J. Twomey, Jade Alice Eaton and *Richard L. Roberts*; *Robert H. Loeffler, W. Stephen Smith* and *Jonathan Band*; with whom *Douglas B. Baily* and *Bruce Botelho* appeared on the briefs, for the State of Alaska.

William W. Becker for Arctic Slope Regional Corporation.

Dennis H. Melvin and *Arnold H. Meltz,* with whom *William J. Froehlich* and *Thomas J. Burgess* appeared on the briefs, for the staff of the Federal Energy Regulatory Commission.

Endicott Pipeline Company (EPC) operates one of the interstate oil pipelines on the North Slope of Alaska. This case is to determine whether the proposed initial rate which EPC has filed with the Federal Energy Regulatory Commission is just and reasonable under sections 15(7) and 15(1) of the Interstate Commerce Act, 49 U.S.C. § § 15(7) and 15(1).[1]

EPC, a partnership, is owned principally by four major oil companies: The British Petroleum Company p.l.c. (which holds the largest financial interest in the partnership); Exxon Corporation (which holds the next largest interest); Unocal Corporation; and Amoco Corporation (*See* exhibits 1-0, pp. 3-9; 1-12; 1-13; 1-14; 1-14.1; 1-14.2; Tr. 246-56). The primary task of the 25-mile pipeline is to transport its parents' crude oil, extracted from the Endicott field located offshore Alaska in the Beaufort Sea, to pump station no. 1 of the main north-south pipeline of the state, the 800-mile Trans Alaska Pipeline System (TAPS).[2] There, the oil, while being commingled with oil extracted from yet other North Slope fields, is moved south to market, which includes the lower 48 states (exhibits 2-0, pp. 2-8; 2-1 through 2-10; Tr. 196-201; 258).

In early October 1987, EPC began to transport oil from the Endicott field to TAPS, thereby commencing its role as a feeder-pipeline (Tr. 258-59). Transportation started after an employee board of the Commission (49 U.S.C. § § 17(2)-(9)), the Oil Pipeline Board, briefly suspended the company's proposed initial rate of 71 cents per barrel, and then allowed the rate to become effective subject to refund pursuant to section 15(7). *Cf. Trans Alaska Pipeline Rate Cases*, 436 U.S. 631, 651, 654-57 (1978) (*TAPS*).

In setting the proposed rate for hearing, after receiving complaints about the proposal from the State of Alaska and Arctic Slope Regional Corporation (ASRC), another North Slope landowner, the Board found that EPC had not shown the rate to be just and reasonable. The Board expressly noted that the rate might be unjust and unreasonable or otherwise unlawful under the Interstate Commerce Act (Order issued September 30, 1987, at pp. 2-3).

EPC expects to terminate its pipeline operations when production from the Endicott field ceases. Stated somewhat differently, the pipeline is deemed to be a single-asset operation whose service life is tied to oil being produced from the Endicott field (Tr., *e.g.*, 297-98; 365; 730-31; 775).

The FERC staff has joined with Alaska on many but not all issues to oppose in large part EPC's proposed rate, contending that the rate is too high and needs to be reduced. ASRC, on the other hand, after intervening here has elected to sit quietly on the sidelines playing no active role in the case.

Countering the arguments of Alaska and the staff, EPC asserts that it has acted moderately by keeping its rate down in spite of compelling evidence which would have reasonably allowed it to set the rate even higher.

For the reasons below, it is concluded that EPC has not fully sustained its burden to prove that the proposed rate is just and reasonable.[3] The rate must be lowered. There is also evidence demonstrating that the rate should not be fixed or constant but rather should be variable, so that it is adjusted monthly, in order to prevent EPC from reaping a recurrent unwarranted windfall.

In contrast with a variable rate, a fixed rate ignores the fact that for purposes of calculating a return (one of the major cost-elements of a rate), the dollar amount known as "rate base" is generally declining and will expire altogether insofar as EPC is concerned. In addition, a fixed rate disregards the fact that recovery of another major cost-element, depreciation, has been accelerated and, thus, the cost itself will

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[1] The Interstate Commerce Act regulates segments of various modes of interstate surface transportation, including rates of oil pipelines. Although the Interstate Commerce Commission traditionally has administered the Act, Congress transferred jurisdiction from the ICC to the FERC to administer the Act concerning oil pipeline rates beginning October 1, 1977 (42 U.S.C. § § 7172(b) and 7341, together with Exec. Order No. 12,009, 3 C.F.R. at p. 142 (1978)).

About a year after the transfer of jurisdiction, Congress—with the exception of that portion of the Act relating to oil pipelines—recodified or, in some instances, repealed the rest of the Act (Act of October 17, 1978, sections 4(b) and 4(c) (Repeals and Savings Provisions) of Pub. L. No. 95-473, 92 Stat. 1337, 49 U.S.C. § 10101 *et seq.*). Accordingly, statutory references in this decision are to the "old" Interstate Commerce Act (*see generally* 49 U.S.C. § § 1-26), not the "new" Act whose sections resemble a zip code (*see generally* 49 U.S.C. § 10101 *et seq.*). *See also* footnote 9, *infra*.

[2] Over 98% of the oil extracted from the field and moved by the pipeline is owned by the four parent companies mentioned. The small remainder of the oil extracted from the field and moved by the pipeline is owned by others (exhibit 1-0, p. 6; Tr. 102; 250-51 and 253).

[3] Suspension, albeit brief, of EPC's proposed rate achieves the goal of preventing irreparable harm to the public while the Commission considers the lawfulness of the proposal. The foundation for the suspension is the Commission's (or its employee board's) conclusion that the proposal has not been shown to be just and reasonable, and that it may be unjust and unreasonable. *Cf. TAPS, supra*, 436 U.S. at 652-53. Consequently, the ultimate burden of persuasion rests upon EPC to show that its proposal is just and reasonable.

decrease more rapidly than it otherwise would due to a methodology which EPC has elected to use. Consequently, a fixed rate in these circumstances will be unduly high because it will necessarily exceed EPC's costs.

EPC argues that even if a fixed rate for the company may be too high, the Commission lacks the power to order the use of a variable cost-tracking tariff while passing upon the lawfulness of the company's proposed initial rate. EPC's argument is not persuasive. Nevertheless, in view of the Commission's recent determination in *Kuparuk Transportation Co.*, 55 FERC ¶ 61,122 (slip opinion issued April 25, 1991, at pp. 7-12), that the agency does lack the statutory authority, a variable tariff will not be ordered here.

I

A

In the years since jurisdiction has been transferred to the Commission to administer the Interstate Commerce Act regarding oil pipeline rates (n.1, *supra*), the agency has not addressed a number of questions through rulemaking or adjudication. This regulatory gap not only delays proceedings and increases the issues that need to be decided when an oil pipeline rate case is set for hearing, it invites additional arguments to be advanced which should have long since been laid to rest.

EPC, for example, continues to press its argument that the Interstate Commerce Act is primarily confined to protecting the interests of shippers alone (Initial brief, pp. 3-4). The argument was rejected earlier in this case when ASRC was seeking to intervene (presiding judge's order issued October 22, 1987). EPC revives the argument at this stage as it tries to minimize or block Alaska's opposition to its proposed rate.

Alaska, to be sure, is not a shipper using EPC's service. But the state has a genuine financial stake in the outcome of this proceeding. As a landowner and taxing authority, Alaska stands to lose revenues (royalties and taxes) if EPC's rate is set unduly high. Under a "netback" methodology, the tariff rate is deducted by each parent company of EPC as a transportation cost in calculating its royalty and tax payments owed to the state on the oil extracted from the Endicott field (Tr. 102-04).

Because EPC is not an independent pipeline, but instead is jointly owned and controlled by parent company-shippers, the parents actually pay themselves when EPC transports their oil. Thus, with regard to Alaska, the parents have an economic incentive to keep EPC's tariff rate as high as possible (*id.*). Conversely, because Alaska's revenues hinge upon EPC's tariff rate, the Commission must stay alert to the possibility that the state may be unreasonably trying to set the rate at an unduly low level.

Although EPC suggests that none of these economic questions regarding Alaska should be of concern to the Commission under the Interstate Commerce Act, that is simply not so. The Act certainly covers the interests of carriers and shippers, but it does not stop there. It deals with the "public"—a comprehensive term entailing countless subjects. Among the topics which the Act addresses are questions affecting labor as well as landowners-taxing authorities like Alaska. *See, e.g., Brotherhood of Maintenance of Way Employees v. United States*, 366 U.S. 169, 170-72 (1961); *TAPS, supra*, 436 U.S. at 635 and nn.6-8, 644, 655; *Exxon Pipeline Co. v. United States*, 725 F.2d 1467, 1472 (D.C. Cir. 1984) and at 1486-87 (Wright, J. *concurring*).

It is, therefore, erroneous for EPC to argue that the Interstate Commerce Act has a different statutory purpose than other statutes which the Commission traditionally has administered, such as the Natural Gas Act or the Federal Power Act. All of these statutes have a common denominator—a congressional edict that the Commission balance the interests of regulated entities with the public.

Moreover, apart from Alaska's interest, the Commission has an independent duty under sections 1(5)(a), 15(1), and 15(7) of the Interstate Commerce Act, 49 U.S.C. § § 1(5)(a), 15(1), and 15(7), to assure that EPC's proposed rate is just and reasonable. It is for that reason, presumably, the staff has taken an active role in this case.

That role has not been made easier by the regulatory gap which exists with regard to oil pipeline rate tariffs. By not requiring oil pipelines to submit detailed cost and revenue data, based on a specific "test period," which its own regulations compel electric utilities and natural gas companies to present to the Commission while seeking a change in a rate tariff,[4] the Commission slows down the process of evaluating an oil pipeline's proposal and adds to the issues that need to be decided when a proposal is set for hearing.

The point is no different where an initial rate is involved, such as EPC's proposal under review here (18 C.F.R. § 341.57). Compared

[4] *Compare* 18 C.F.R. § § 35.13, particularly (d)(1)-(5), and 154.63, particularly (e)(2), *with* 18 C.F.R. § § 341.2, .9, .54; and *see American Public Power Ass'n v. FERC*, 522 F.2d 142 (D.C. Cir. 1975); *NEPCO Mun. Rate Comm. v. FERC*, 668 F.2d 1327, 1339 (D.C. Cir. 1981), *cert. denied sub nom., New England Power Co. v. FERC*, 457 U.S. 1117 (1982).

with an oil pipeline, an electric utility proposing an initial rate can be required by the Commission to submit "complete cost studies" (18 C.F.R. § 35.12(b)(2)(ii)). Though a natural gas company proposing an initial rate is not subject to such a requirement (18 C.F.R. § 154.62), that is largely because its rate is not judged at the outset under the just and reasonable standard of section 4 or 5 of the Natural Gas Act, 15 U.S.C. §§ 717c, 717d. Rather, given the fact that the initial rate accompanies issuance of a certificate under sections 7(c)-(e) of the Act, 15 U.S.C. §§ 717f(c)-(e), the Commission merely determines at the time of certification whether the rate is "in line" with rates for similar service. After service begins pursuant to the certificate, the Commission then is to conduct a thorough evaluation under section 4 or 5 (obtaining in the process all necessary cost and revenue data) to determine that the rate will be just and reasonable. *Cf., e.g., Atlantic Refining Co. v. Public Service Comm'n*, 360 U.S. 378, 390-92 (1958)(*CATCO*); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 227-29 (1965); *FPC v. Sunray DX Oil Co.*, 391 U.S. 9, 36-40 (1968).

No such certification procedure is required for an oil pipeline under the Interstate Commerce Act. The time, therefore, to study the lawfulness of its proposed rate is when the rate is filed with the Commission. Yet, as noted, the Commission's regulations do not require the submission of detailed cost and revenue data based upon a specific test period.

True, after its first effort not to regulate oil pipeline rates with great care was found wanting and in contravention of the Interstate Commerce Act, *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486 (D.C. Cir.), *cert. denied*, 469 U.S. 1034 (1984) (*Farmers Union* II), the Commission has announced some generic cost-based guidelines for these rates. *See Williams Pipe Line Co.*, 31 FERC ¶ 61,377 (1985) (Opinion No. 154-B), *reh'g denied in part*, 33 FERC ¶ 61,327 (1985) (Opinion No. 154-C). But by no means are the guidelines complete or absolute.

EPC recognizes that the *Williams* guidelines are far from complete, pointing out that where they are "vague or silent" it has attempted to use traditional gas or electric ratemaking principles to support its proposed rate (Initial brief, p. 5). It is also beyond quarrel that the guidelines are not absolute the Commission having left the door open for exceptions to be made to the guidelines.

For example, while adopting "trended original cost" (TOC) as the means to calculate part of the rate base of an oil pipeline (as described more fully below), the Commission also acknowledged in *Williams* that TOC may present problems especially for new pipelines. Thus, in place of TOC, the Commission invited alternative "innovative solutions" to be presented to it in a given case (31 FERC at p. 61,839 n.22; *cf.* 31 FERC at pp. 61,833-35). As another example, while seemingly announcing that it would use the actual capital structure of an oil pipeline or its parent for calculating a return (31 FERC at pp. 61,833 and 61,836), the Commission went on to qualify the announcement. It would "allow participants on a case-specific basis to urge the use of some other capital structure" (31 FERC at p. 61,833).

In short, while the D.C. Circuit's *Farmers Union* II decision, *supra*, attempted to provide some guidance to the Commission in evaluating oil pipeline rates under the statutory just and reasonable standard, there are still virtually no ironclad ground rules to be applied. Consequently, when such a proposed rate is set for hearing, the participants have substantial freedom to urge that their respective positions be adopted.

B

To understand the questions to be decided in this case, it is useful first to go over certain cost-based ratemaking principles which should apply to a public utility regardless of whether it is engaged in oil, natural gas, or electric transmission. Then, it helps to discuss briefly where the Commission has attempted to draw a distinction for ratemaking purposes between an oil pipeline, on the one hand, and a natural gas company or electric utility, on the other. This was done in *Williams* (post-*Farmers Union* II) by the agency's adoption of TOC[5] for an oil pipeline, subject to possible exception in a particular case.

Generally, a public utility is permitted to charge its customers on a prospective basis for the ordinary and necessary costs which it anticipates incurring over a definite time period, usually at least a year in length, to provide service to them. The costs, often referred to collectively as a cost of service, consist of the following four components—operating and maintenance expenses (the day-to-day costs of providing service); depreciation (which recovers the debt and equity capital invested in the facilities or plant used to provide service); taxes to be paid, including federal income taxes; and return (which compensates a utility, after taxes have been paid, for such costs as obtaining and making use of the debt and equity capital invested).

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[5] This case has more than its share of abbreviations or acronyms, such as TOC. An effort will be made not to overuse these references in order to avoid having the discussion or analysis become too murky.

Rate base is the dollar figure upon which a public utility is permitted to earn a return. It is this element which the Commission has announced it is prepared to treat differently, in part, insofar as an oil pipeline is concerned, on the one hand, compared to a natural gas company or an electric utility, on the other.

In the case of a natural gas company or an electric utility, rate base consists of the total debt and equity capital invested in plant, minus accumulated depreciation (i.e., the net investment in facilities). At times, rate base is further adjusted upward or downward to account for certain expenditures which the utility/company either incurs presently or will incur in the future.

The debt and equity capital reflected in the rate base of such a utility/company is listed at its original cost. It is original cost, not a future replacement cost, which is recovered from ratepayers through a depreciation charge. As the capital or investment is recovered in this manner, it is deducted concurrently from rate base, dollar-for-dollar.

To determine the return to be allowed, a weighted average rate (composed of the different "nominal" rates of return applying to the debt and equity, preferred and common) is multiplied against the rate base. According to economists, a nominal rate consists of a "real" rate, plus other costs including inflation.

In comparison to the procedure described above, the Commission decided in *Williams* to adopt TOC for an oil pipeline, subject to possible exception in a specific case. As for the debt capital of such a pipeline, it is to be listed in the rate base at its original cost (just as in the case of a natural gas company or an electric utility). It is the equity-portion of an oil pipeline's rate base where TOC comes into play and differs from the traditional approach used for a natural gas company or an electric utility.

For a new oil pipeline, TOC starts with the original cost of the equity. However, rather than multiplying a nominal rate or rates against the original cost-equity (common and, possibly, preferred), TOC separates the real rate from the inflation-portion. The real rate and the inflation-portion are then each multiplied against the equity.

Use of the real rate determines the return which an oil pipeline is permitted to earn or recover currently. Use of the inflation-factor determines the amount to be added to the equity-portion of the rate base annually, which ever-growing amount is to be "capitalized" (i.e., recovery of the amount is to be spread or amortized over the remaining service life of the plant, which can be years). Recovery, through amortization, of the capitalized inflation-adjusted amount starts in the first year of operation of the pipeline, thereby causing a concomitant reduction dollar-for-dollar of the equity-portion of the rate base.

Essentially, what happens through the TOC methodology is that depreciation of the original cost-rate base (debt and equity) of a new oil pipeline is not affected. Through a depreciation charge, the original cost will be recovered and, as this is done, will result in a concomitant reduction from rate base, dollar-for-dollar. However, netted against the reduction in rate base (due to depreciation) is the addition to the equity-portion of the rate base (due to TOC) of the capitalized amount for inflation, less the recovery or amortization each year of the inflation-amount.

The net effect of the TOC methodology is that even though over time the rate base of a new oil pipeline will go down and eventually reach zero, assuming there are no capital additions to plant, the equity-portion can go up or down in a given year. The Commission itself illustrated in *Williams* (Opinion No. 154-B), *supra*, how, without considering other possible factors, the equity-portion will go up from year-to-year, at least during the earlier years of an oil pipeline's operations, despite the fact that there are no additions to plant (31 FERC at p. 61,834 and p. 61,839 n.21). Conversely, the equity-portion of the rate base will go down, in the absence of capital additions to plant, when the annual depreciation of original cost-equity capital, together with the annual amortization of the ever-growing inflation-adjusted amount, exceed the inflation amount for that year.

In sum, TOC is a deferral methodology whereby ratepayers are assessed, for the return on equity, lower charges in the earlier years (compared to what the charges would have been if TOC had not been used) and higher charges in the later years of a new oil pipeline's operations. If ratepayers' financial burdens are eased somewhat in the earlier years (through the use of a lower real rate, rather than a higher nominal rate, to determine a return on equity), there is still a major price that they must pay eventually. It will consist of the ever-growing inflation-adjusted amount which is being amortized, plus the deferred return (together with associated income taxes) for that part of the equity return which had not been collected earlier in rates. Stated another way, over time ratepayers may well pay more than they would have if TOC had not been used, but instead the traditional nominal-rate methodology (which is applied to natural gas companies and electric utilities) had been used.

The Commission adopted TOC for new oil pipelines because of its desire to foster intramodal and intermodal competition to transport oil. As the agency viewed the matter in *Williams* (Opinion No. 154-B), *supra*, subject to possible exception in a specific case, TOC mitigates a "front-end load problem" for a new oil pipeline by allowing the pipeline to defer to a later time collecting a higher return associated with a large rate base, thereby enabling it to avoid bunching return income in the earlier years so that it can then compete for traffic with older pipelines and other transportation modes whose rate bases are lower (31 FERC at pp. 61,834-35; *see also Farmers Union* II, *supra*, 734 F.2d at 1516-17).

EPC has proposed using TOC in the case at bar for its initial rate. At the same time, with regard to certain major costs apart from return (such as depreciation), EPC is proposing to use another methodology—called the unit-of-throughput (UOT), also commonly known as the unit-of-production—which will enable it to recover these costs more rapidly in the earlier years of its operations. The upshot of the UOT methodology is that it front-end loads these costs.

C

EPC filed its initial rate tariff with the Commission in the latter part of September 1987, proposing that the tariff become effective 10 days later at the beginning of October 1987. The tariff was filed as the company completed construction of its new feeder-pipeline to transport its parents' crude oil from the offshore Endicott field to TAPS. Most of the pipeline is aboveground; none of it is underwater (Tr. 354; exhibit 2-8).

No cost or revenue data was proffered by EPC with the filing to support the proposed rate of 71 cents per barrel. Such data was first submitted by the company at the direction of the Commission's Oil Pipeline Board after the Board, upon receiving complaints about EPC's filing from Alaska and ASRC, had suspended the rate proposal briefly. The one-day suspension elapsed on October 2, 1987, when the rate became effective subject to refund (order issued September 30, 1987).

With no regulations specifying a definite test period to be used to measure the justness and reasonableness of its rate, EPC selected calendar year 1988 to project the attendant costs and revenues. According to the company, these yet-to-be-incurred costs and revenues had been budgeted or estimated in 1987 for 1988 (exhibit 4-0, pp. 12-15; exhibit 4-3, Schedule No. 1). Based upon these estimates, EPC tried to show that by using both the TOC and UOT methodologies its costs would justify a fixed rate of at least 71 cents per barrel (exhibits 4-2 and 4-3, including exhibits 4-3.1 through 4-3.8; *see also* exhibit 4-0, pp. 14-15).

About a year later, toward the end of 1988, Alaska and the staff each responded to EPC's presentation by focusing upon the company's "actual" costs—i.e., those that had been incurred for 1987 (starting when the pipeline began operations) and those that were then known for 1988.[6] Even some of the actual costs were based upon certain assumptions. Because Alaska and the staff viewed these costs, albeit on somewhat different grounds, as being lower than the costs used by the company to justify its 71-cents rate, each urged that EPC reduce its rate accordingly for 1987 and 1988 (exhibit 12-2.1; *see also* exhibit 12-0, p. 4; exhibits 16-2, Schedule No. 1A; 16-3, Schedule No. 1B; *see also* exhibit 16-1, pp. 5-6).

To determine the rate for the years 1989 and thereafter, the staff proposed using a test year-approach in part (based upon actual costs for calendar year 1988, as adjusted), which would then be further adjusted for annual changes concerning net investment, throughput (i.e., the volume of oil moving through the pipeline), and tax rates (exhibit 16-1, pp. 6 and 13-16; exhibit 16-3, Schedule No. 1C). Alaska, on the other hand, urged that the rate not be fixed or constant (and, thus, not be based upon a test year-approach), but rather that it be variable to reflect the annual changes regarding all of EPC's costs.

Alaska has labeled its proposal to determine the rate a "variable tariff methodology" (VTM) (exhibit 13-0, pp. 52-57; *see also* exhibits 12-0, p. 4, and 12-2.1). The staff has dubbed its proposal a VTM also, even though its proposal is more qualified or limited than Alaska's. Perhaps Alaska's proposal can be better described as an unlimited VTM, while the staff's proposal can be regarded as a limited VTM.

Alaska also commented upon EPC's efforts to use the TOC and UOT methodologies to justify its rate. While calculating the rate on the basis of TOC, Alaska has expressed concerns about applying TOC here (Initial brief, pp. 3-5). Otherwise, Alaska fully supports use of the UOT methodology for various costs, including depreciation. The staff, on the other hand, only agrees to use UOT for depreciation (*see* exhibit 1-9, pp. 5-6), not for other costs or expenses to which EPC also has applied the methodology.

Among such other costs are those for dismantling, removal, and restoration (DR&R), which

[6] When Alaska and the staff each filed written testimony and supporting exhibits, information was available only with regard to EPC's actual costs for the first 9 months of 1988. Estimates were therefore used for the last 3 months of the year (*See* exhibit 4-6, p. 31).

EPC expects to incur when the pipeline finally goes out of service and is retired. The staff asserts that these costs (to be described in more detail below) are too contingent and, thus, should not be reflected at all in EPC's rate. In any event, the staff contends that even if the DR&R expenses are to be reflected in the rate, they should not be calculated on a UOT basis (exhibit 20-4, Schedule No. 1; exhibit 16-3, Schedule No. 1C).

In rebuttal to the presentations made by Alaska and the staff, EPC argues that the Commission lacks statutory authority to order the use of a VTM, limited or unlimited, and that in any event such a methodology is not needed here. On the other hand, the company has agreed—subject to certain exceptions and assumptions—to use the actual costs (as compared to the initial estimates) for 1988. As a result, EPC has acknowledged that the overall costs would be lower than its initial estimates (exhibits 4-5.11 and 4-6, pp. 38-39; *compare* exhibit 4-5, including exhibits 4-5.1 through 4-5.10, *with* exhibit 4-3, including exhibits 4-3.1 through 4-3.8; *see also* presiding judge's order issued June 21, 1989).

II

A

EPC is not the first Alaskan North Slope interstate oil pipeline, though it may be the first to operate offshore. Recently, the Commission issued a decision with regard to another North Slope interstate oil pipeline. *Kuparuk Transportation Co., supra*, 55 FERC ¶ 61,122 (1991). Prior to the Commission's decision, conflicting arguments had been advanced here by the parties trying to compare or distinguish EPC and *Kuparuk*.

While attention must be paid to the Commission's decision, especially concerning interpretations of law, it is far from clear in what ways EPC and *Kuparuk* are similar or different factually (*see, e.g.*, EPC's reply brief, p. 18). Therefore, except where expressly noted, the rulings that follow will deal solely with the specific circumstances of EPC given the fact that *Kuparuk's* relevance to the case at bar is uncertain.

EPC, as noted, has elected to use two cost-recovery methodologies—TOC and UOT—to try to justify its proposed fixed rate of 71 cents per barrel. Even though each methodology deals with different costs, there is an inherent inconsistency in relying upon the two together. In the circumstances of this case, the rational way to handle the inconsistency is to continue to make use of UOT but to discard TOC.

TOC is concerned solely with the equity-portion of return. For a new pipeline, it is intended to avoid so-called front-end loading of equity-return costs, associated with a large equity-rate base, by allowing the pipeline to defer to a later time collecting an even higher return allowance. Through this methodology, the Commission believed (as it stated in *Williams*) that a new oil pipeline would be able to avoid bunching equity-return income in the earlier years so that it could compete for traffic with older pipelines and other transportation modes whose rate bases were lower (31 FERC at pp. 61,834-35).

UOT, in comparison to TOC, is not a deferral methodology at all. To the contrary, it accelerates recovery of certain costs in the earlier years of operation of a new pipeline which is to serve, almost exclusively, a recently developed oil reservoir. This is because the cost-recovery is linked to the "production-yield" or so-called production profile of the reservoir.

A reservoir's physical characteristics are such that, whether as a result of natural causes or other production-recovery techniques, larger volumes of oil are extracted in the earlier years than in the later years of the reservoir's life. If a graph were used to illustrate this fact, the production profile would reflect a curve that declines rather substantially after the first few years and then continues on a downward slope throughout the rest of the reservoir's life (*see* exhibit 2-11).

Because the Endicott pipeline's service life is tied to oil being produced from the Endicott field, and inasmuch as there are no storage facilities at the field (Tr. 297-98), oil extracted from the field must move at once through the pipeline—i.e., the unit of throughput tracks the unit of production (exhibit 2-0, pp. 9-13; exhibit 2-11; exhibit 4-4; exhibit 5-0, pp. 3-5; exhibit 5-1, p. 3). Hence, the greater the volumes of oil that are extracted and transported in the earlier years, the greater the amount of costs that can be recovered during that time.

In the case at bar, EPC proposes to apply the UOT methodology to recover a number of costs. Among these are depreciation, DR&R, and certain capitalized items including some relating to federal income taxes and another relating to the amortized deferred return resulting from TOC (exhibits 4-5.4 through 4-5.11; *see also* exhibit 4-4.1). Using the Commission's jargon, UOT front-end loads these costs—the very opposite of what TOC is intended to achieve, albeit with different costs.

There are convincing reasons in this case why the TOC methodology should not be adopted while the UOT methodology should be approved. To begin, the Commission's principal rationale expressed in *Williams* for using TOC—to foster intramodal and intermodal competition to transport oil (31 FERC at pp.

61,834-35)—has no relevance in the present case. It is undisputed that but for EPC, there would be no other means to transport oil from the Endicott field. In the context of this particular Alaskan field, transportation-competition is entirely chimerical.

Moreover, in its effort to avoid front-end loading of equity return costs, TOC causes such costs to be imposed in higher amounts on fewer volumes of oil at the back-end, in the waning years of a reservoir's and thus a single-asset pipeline's lives. If such transportation costs were too high, they could well act as a disincentive to produce the remaining volumes of oil in the reservoir. In the context of the Endicott field, it is simply not worth the gamble to the State of Alaska (which stands to enjoy greater tax and royalty revenues from greater production) and presumably EPC's parents (despite their unsupported proposal to apply TOC here) to insist upon the use of a theoretical TOC methodology which could be pernicious by dampening production.

The Commission itself recognized in *Williams* that TOC might not be appropriate in every oil pipeline rate case and thus invited alternative solutions to be presented to it in a given case (31 FERC at p. 61,839 n.22). This, it is submitted, is such a case. The reasonable solution is to use so-called depreciated original cost for both debt and equity capital (as is done with natural gas companies and electric utilities), to determine rate base and the respective returns, applying in the process nominal rather than real rates of return.

One of the crucial reasons why TOC should not be adopted here argues conversely in favor of approving the UOT methodology. That reason centers on the Commission's role not to erect unnecessary barriers which could discourage efforts to maximize oil production from the Endicott field. Stated more directly, while TOC can deter production in the later years of the field's life, UOT can help accomplish the opposite result by stimulating such production.

This can come about because in the earlier years of the field's and the pipeline's lives when greater volumes of oil are extracted and thus transported, UOT not only accelerates cost-recovery, it also spreads the greater costs over the greater volumes proportionately. Consequently, through this approach UOT helps to assure that in the later years when these same types of costs are lower and are being spread proportionately over less volumes, there is more incentive to continue production until the remaining volumes of oil have been extracted from the field.

It is hardly surprising that Alaska (exhibit 12-0, pp. 15-17) fully supports EPC's proposal to apply UOT to various costs (exhibits 4-5.4 through 4-5.11; *see also* exhibit 4-4.1; exhibit 5-0, pp. 3-5; Tr., *e.g.*, 730-35). Both the state and EPC's parents can enhance their respective revenues through this methodology. There is good reason to allow them to do so.

The staff, on the other hand, agrees that UOT can be used, but only for depreciation covering the years 1987-1990 (exhibit 1-9, pp. 5-7). While not articulating its views as to whether UOT should be applied to depreciation beginning with calendar year 1991 (*cf.* exhibit 1-9, p. 6, paragraph 6), the staff has in fact applied that very methodology for depreciation in its modified test-year cost of service to calculate EPC's future rates (exhibit 16-3, Schedule No. 1C; exhibit 16-6, Schedule Nos. 8A-C; *see also* exhibit 19-3).

With regard to EPC's proposal to use UOT for certain other costs, the staff opposes the proposal. Instead, the staff urges the use of a "straight-line" methodology, whereby the same amount of costs would be recovered each year notwithstanding the fact that the costs would be spread over ever-diminishing volumes of oil extracted and transported in the later years of the Endicott field's and pipeline's lives (exhibit 16-3, Schedule Nos. 1C and 3B.1; exhibit 20-1, p. 15; exhibit 20-4, Schedule No. 1).

The staff's argument concerning which costs should be subject to UOT is neither consistent nor persuasive. Having itself agreed to apply UOT to the largest of these costs, depreciation, not only for 1987-1990 but presumably for 1991 and beyond, the staff has failed to make a convincing showing as to why it would be reasonable to change to another methodology, straight-line, for each of the smaller, remaining costs (Tr., *e.g.* 2117-22).

Among these remaining costs is DR&R. When production from the Endicott field terminates, thus causing the Endicott pipeline to shut down permanently, EPC anticipates having to bear substantial costs to dismantle (d) and remove (r) facilities and to restore (r) affected areas. These costs have been estimated by the participants in this case to be $15 million if 1987 were used as the base year or period[7] (exhibit 1-10, p. 1). EPC's initial rate reflects these estimated DR&R costs, among other items, and accelerates recovery of the estimates by applying UOT.

[7] Because of the economic concept known as the time value of money, the dollar equivalent of $15 million (where 1987 is the base period) will be a much greater amount in the future, sometime after the year 2000, when the pipeline finally is shut down.

The staff takes issue with EPC's treatment of DR&R on a number of grounds, including its use of UOT rather than a straight-line procedure which the staff favors. Only the UOT ground will be considered now. The other grounds assailing EPC's handling of DR&R will be addressed later in this decision.

The staff does not like the fact that UOT accelerates the recovery of DR&R in the earlier years (Tr. 2117-18). But while expressing what it dislikes, the staff chooses to say nothing about other compelling facts.

One is that the acceleration results from the larger volumes of oil produced and transported in the earlier years. At the very least, the larger costs are being spread over the larger volumes, thereby assuring a proportionate distribution of such costs. A second important fact is that in the later years, when these same types of costs are lower, they will be spread proportionately over less volumes, thereby acting as an incentive to continue production until the remaining volumes of oil have been extracted from the Endicott field.

In comparison, the staff's proposed straight-line procedure does not accomplish these beneficial goals, and it is hereby rejected. Because the same amount of costs would be recovered each year through straight-line, there would be no proportionate spreading of the costs, especially in the later years when there would be diminishing volumes of oil extracted and transported. Of equal importance, as the costs remain the same despite the fact that the volumes are decreasing, a straight-line methodology (somewhat like TOC) could well act as a disincentive to produce the remaining volumes of oil in the Endicott reservoir.

To summarize, with one exception, EPC is authorized for 1987-1990 as well as 1991 and beyond to apply the UOT methodology to the various costs—depreciation,[8] DR&R, and certain capitalized items—that it has proposed. The exception is for the amortized deferred return resulting from TOC. Because TOC has been ruled to be unreasonable in the circumstances of this case, there will no longer be such a deferred return.

B

In view of the fact that EPC is authorized to use the UOT methodology for a number of costs, it follows that while recovery of these costs is accelerated in the earlier years, recovery of these same types of costs will decelerate or slow down in the later years of the Endicott project. In short, recovery of the costs will not be uniform from year-to-year throughout the project's life, but rather will keep on declining over time.

EPC's rate base, in particular, will reflect this downward trend. The company is depreciating debt and equity capital using UOT, which has the concomitant effect of reducing the rate base in the earlier years by the larger (depreciated) amounts dollar-for-dollar. Given the fact that the TOC methodology has been rejected here, there will be no deferred return and thus no possible increase in the equity-portion of the rate base due to that methodology.

In addition, EPC is using an even more accelerated depreciation methodology for federal income tax purposes, thereby producing for ratemaking purposes an accumulation of deferred taxes which further reduces (apart from depreciation) the company's rate base (exhibit 4-5.9; exhibit 5-0, pp. 4-8). Then, too, it needs to be remembered that the pipeline is a single-asset operation whose service life is tied to oil being produced from the Endicott field (Tr., *e.g.*, 297-98; 730-31; 775). This means that the possibility of increasing EPC's rate base by investing additional capital in plant—while it cannot be ruled out altogether (*cf.* exhibit 13-29)—is nowhere near as great as it would be if the pipeline were serving or proposing to serve multiple oil fields.

In sum, there is a reasonable likelihood that EPC's rate base will continue to decline. Accordingly, there is a reasonable likelihood that the company's so-called return allowance which is reflected in its rate (and calculated by multiplying the rate base by a weighted average rate of return) will continue to decline.

In these circumstances, there is every reason not to set a fixed initial rate for EPC whereby the company would charge the same amount year-after-year even if its costs (as appears likely will occur) keep decreasing. Such a constant rate would not reflect EPC's costs and necessarily would be unduly high because it would exceed the costs. The reasonable solution would be to require the initial rate to be variable, so that it would be adjusted monthly to track the company's costs, in order to prevent EPC from reaping a recurrent unwarranted windfall.

EPC asserts that a variable tariff methodology (VTM), limited or unlimited, is not needed here. But the company spends little time on the point (initial brief, pp. 70-72) and fails to support its assertion. Instead, EPC primarily argues that the Commission lacks the statutory authority to order the use of such a methodol-

[8] *See* the Oil Pipeline Board's order issued February 6, 1991 in Docket No. IS87-36-001 [54 FERC ¶ 62,093].

ogy over the company's objections, while also questioning how the methodology actually would work.

EPC's argument is unconvincing. After discussing the reasons for this conclusion, this decision outlines how the methodology would work.

Premised upon what it labels its fundamental right to initiate rates, EPC argues that the Commission cannot interfere with this right through the imposition of a cost-tracking tariff (Initial brief, pp. 67-69). To support its argument, EPC rests upon a decision of the D.C. Circuit, *Public Service Comm'n of New York v. FERC, 866 F.2d 487 (1989) (PSCNY)*, which the company describes as having addressed "a nearly identical legal issue in an analogous setting under the Natural Gas Act" (*id.*, p. 68).

The argument glosses over the facts of this case, makes an unwarranted assumption, and improperly relies upon *PSCNY* while minimizing the Commission's role in the ratemaking process. To begin, EPC initiated the proposed rate under consideration here, and nothing, even the imposition of a variable cost-tracking tariff, would prevent the company from initiating filing any future proposed rates that it chooses. But any rate proposal of the company is subject to ultimate determination by the Commission for its lawfulness. If the company at times starts the process, the Commission has the final say subject to judicial review.

Moreover, it is essential to keep in mind the facts of this case. What is being reviewed here for its lawfulness is the proposed initial rate of EPC. Though the company has been collecting the rate for years subject to refund, the rate itself has never been approved by the Commission. This fact alone distinguishes the present case from at least two decisions of the D.C. Circuit upon which *PSCNY* relies (866 F.2d at 490-91)—*Panhandle Eastern Pipe Line Co. v. FERC*, 613 F.2d 1120 (1979), *cert. denied*, 449 U.S. 889 (1980); *Northern Natural Gas Co. v. FERC*, 827 F.2d 779 (1987) (en banc).

In *Panhandle* and *Northern Natural*, it was decided that the Commission's power to impose conditions upon rates does not extend to adjusting previously approved rates for services not then pending before the agency in a given proceeding. To hold otherwise, the court reasoned, would blur what was perceived to be the bright line between changing rates when initiated by the Commission upon its own motion or a complainant, on the one hand, or a regulated entity, on the other (613 F.2d at 1129-30; 827 F.2d at 792-95). The case at bar, in contrast with *Panhandle* and *Northern Natural*, has nothing whatever to do with adjusting rates previously determined to be just and reasonable, let alone with services not pending before the agency in this case.

EPC's argument also rests on the unwarranted assumption that a regulated entity invariably is entitled to the setting of a fixed rate. Grounded upon this proposition, EPC then proceeds to assert that once a fixed rate is established, it must remain in effect until changed under one of two statutory paths. If neither path is followed, according to EPC, the fixed rate cannot be altered and must remain in effect in perpetuity.

The basic error in this thesis is the assumption or claim that a fixed rate always must be used or established, even in the first instance when an initial rate is being determined. Examples abound where the Commission has chosen not to use a fixed rate, but rather has elected to use a variable rate to track some or all costs of a regulated entity.

Natural gas pipelines, for instance, are permitted (without taking action by means of a full-blown rate proceeding) to track or adjust periodically their largest operating cost — gas purchased for resale — through a variable rate, not a fixed rate (18 C.F.R. § § 154.301-.310). So, too, are electric utilities allowed to track or adjust one of their largest costs — fuel used to generate electricity, or electricity purchased from another entity — through a variable rate, not a fixed rate (18 C.F.R. § 35.14). In fact, the Commission on a number of occasions has approved a variable tariff — rather than a fixed rate tariff — which tracks all or almost all costs, not merely one or two selected items. This type of mechanism is often referred to as a cost-of-service tariff or an automatic adjustment or formula rate tariff. *See, e.g., Louisiana Public Service Comm'n v. FERC*, 688 F.2d 357, 360-61 (5th Cir. 1982), *cert. denied*, 460 U.S. 1082 (1983); *Hampshire Gas Co.*, 6 FERC ¶ 61,249, at pp. 61,607-08 (1979); *Maine Yankee Atomic Power Co.*, 52 FPC 76, 78 (1974); *Michigan Gas Storage Co.*, 5 FPC 965, 971 (1946).

It is of no importance that in each of the cases above the regulated entity itself sought or consented to the use of a cost-tracking tariff. The fact is that in each instance a variable tariff, not a fixed rate tariff, was approved and utilized. If the Commission lacked the statutory authority to allow use of a variable tariff, the consent of a regulated entity could not confer such authority upon the agency. *Cf., e.g., Commodity Futures Trading Comm'n v. Schor*, 478 U.S. 833, 850-51 (1986); *United States v. Griffin*, 303 U.S. 226, 229 (1938).

Indeed, if the Commission's jurisdiction to authorize the use of such a tariff turned on consent, it could lead to unreasonable or incongruous results. A regulated entity likely would assent only when a variable tariff advanced its self interest, which might not necessarily coincide with the public interest. Stacking the deck in this manner to achieve one-sided outcomes is hardly a positive sign of congressional intent concerning an agency's jurisdiction, given the fact Congress usually demands that a regulated company's actions be consistent with the public interest (*Cf.* EPC's initial brief, p. 69; *PSCNY*, 866 F.2d at 492).

There have been cases prior to this one where the Commission has turned down a proposal to utilize a fixed rate tariff, and ordered instead the use of a variable, cost-tracking tariff. *See, e.g., Seagull Interstate Corp.*, 32 FERC ¶ 61,261, at p. 61,618 (1985); *Trunkline Gas Supply Co.*, 9 FPC 721, 729 (1950); *see also Trunkline Gas Co. v. FPC*, 247 F.2d 159, 160 (5th Cir. 1957). These cases provide additional support for the fact that, contrary to EPC's assertions and intimations, a fixed rate is not and never has been the one and only way for the Commission to set rates.

Nor is EPC correct in contending that *PSCNY* controls the outcome of the case at bar. To be sure, the Commission was concerned there — just as is true here — with the possibility that a rate might be set too high because of potential declining costs stemming, in whole or in part, from a shrinking rate base (866 F.2d at 489). But in *PSCNY* the Commission eschewed the use of a variable, cost-tracking tariff for the costs at issue (*Id.*). Instead, while approving a fixed rate for the company involved regarding those costs, the agency ordered the company not only to refile its rate every few years, but also to carry the burden to prove that the refiled rate would be just and reasonable (*Id.*).

Upon review, the court in *PSCNY* — relying upon *Panhandle* and *Northern Natural*, among other cases — concluded that the Commission's order was unlawful because it would improperly shift the burden of proof to the company. Borrowing from *Panhandle* (613 F.2d at 1129), the court found that the compulsory refiling and improper shift would "effectively emasculate" the statutory path which imposes the burden upon the Commission or a complainant to change an existing, previously approved rate when the regulated company itself is not seeking to change the rate (866 F.2d at 490-92).[9]

PSCNY is inapposite and does not control the outcome of the present case for at least two reasons. First, in *PSCNY* the Commission set or approved a fixed rate which was to be reexamined every few years, subject to a showing by the regulated company that the previously approved rate was still just and reasonable. Here, in comparison, no fixed rate has been set or approved.

As noted, the 71 cents per barrel initial rate which EPC has been charging for a few years has never been approved and is being collected subject to refund. It would be reasonable in the present case, after evaluating the 71 cents rate, not to set a fixed rate even then. Instead, each month — starting with the first month EPC began charging its rate subject to refund — the rate would be adjusted to reflect any changes in EPC's actual costs.

There is a second reason *PSCNY* is not controlling. The D.C. Circuit in that case did not review for its lawfulness a variable, cost-tracking tariff as would be reasonable to impose here. If it had, the court may have looked with favor upon such a tariff. After all, *PSCNY* traced its lineage to *Panhandle* (866 F.2d at 490-91). In *Panhandle*, while reversing the Commission's rate condition there imposed to deal with a possible overcharge of costs, the court itself urged the use of a variable cost-tracking tariff to handle the matter (613 F.2d at 1133; and *see PSCNY*, 866 F.2d at 491).

It is evident that such a variable tariff should be used in the present case. There is a view that this type of tariff minimizes the business risks of the regulated company involved because the company knows that it will recover its costs, including a return element, whether or not it transacts much business or conducts its operations in a cost-effective or efficient manner. *See, e.g., Northern Border Pipeline Co.*, 52 FERC ¶ 61,102, at

[9] Without addressing the Commission's statutory power when an initial rate is proposed, *PSCNY* discussed the two statutory paths to change rates under the Natural Gas Act — section 4(e) where a regulated entity itself seeks a change and, thus, has the burden of proof, and section 5(a) where the Commission upon its own motion or a complainant seeks a change and, thus, has the burden of proof (15 U.S.C. §§ 717c(e) and 717d(a)).

The case at bar involves a proposed initial rate, not a change, under section 15(7) of the Interstate Commerce Act, 49 U.S.C. § 15(7), which also brings into play section 15(1) of the Act, 49 U.S.C. § 15(1). Section 15(7) provides in part that if a proposed rate subject to that section goes into effect "the Commission may make such order with reference thereto as would be proper in a proceeding initiated after it had become effective [pursuant to section 15(1)]."

Where a change in a rate is sought under the Interstate Commerce Act, section 15(7) again applies (apart from an initial rate) if the change is proposed by a regulated carrier — thus making 15(7) the counterpart to section 4(e) of the Natural Gas Act. If a change is sought by the Commission or a complainant, section 15(1) again applies (apart from an initial rate) — thus making 15(1) the counterpart to section 5(a) of the Natural Gas Act.

p. 61,493 n.7 and p. 61,497 (1990); *Pacific Offshore Pipeline Co.*, 47 FERC ¶ 61,255, at pp. 61,911-12 (1989).

But these potential negative features of a variable tariff are not present in every case. Even if they were present, the Commission has the necessary statutory tools to handle problems that might arise if a variable tariff were used.

In the present case, for example, a variable tariff would have no effect upon how much business EPC transacts. All of EPC's business, the transportation of oil from the Endicott field, hinges upon the volumes extracted from the field principally by the company's parents. EPC and its parents are interdependent — EPC needs its parents' oil to keep its pipeline operating; the parents need EPC, which operates the only pipeline in the area, to help transport to market their oil extracted from the field.

Because the Endicott project's production and transportation are inextricably tied together and are all in the family, there is no reason to be concerned that a variable tariff somehow might encourage EPC to sit back and not care about transacting enough business. Consequently, there would be no need to consider designing, say, a two-part (demand-commodity) rate that would place EPC at risk to recover some of its costs, such as its return on equity and related income taxes, depending upon how much business it conducted.

There is also the question as to whether EPC would take enough interest to operate in a cost-effective or efficient manner if it were subject to a variable tariff. Through its conditioning authority under section 15(7) of the Interstate Commerce Act, the Commission has the means to influence a company's actions so that the company at least would think twice before ever deciding to operate like a spendthrift. Here, the appropriate condition would be to subject to refund (as explained in more detail below) all of the costs recovered by EPC under its variable tariff. Such a condition, tailored to further the public interest, could be attached under section 15(7) because it would be directly related to the Commission's mandate to assure that EPC's initial rate is and remains just and reasonable. *Cf., e.g., TAPS, supra*, 436 U.S. at 653-57; *United States v. Chesapeake & Ohio Ry.*, 426 U.S. 500, 509, 513-15 (1978); *see also I.C.C. v. American Trucking Ass'ns*, 467 U.S. 354, 364-67 (1984).

With the Commission able to deal with any potential negative aspects of a variable tariff, there is no question that such a tariff — when the alternative is a fixed rate tariff — would be the better choice for the Commission to make insofar as EPC is concerned. It would be preferable to allow EPC to use a variable tariff to track its costs and earn a return, so that the company was given an opportunity to be made whole, than to set a fixed rate which likely would enable EPC to receive an undue windfall by overcharging year-after-year as its costs decline. The problem of a constantly overstated fixed rate would not be effectively remedied by holding out the possibility that complaints seeking reparations could be filed. These after-the-fact actions, which would have to be pressed repeatedly, even if successful always would accomplish too little too late, and would never cure the inherent problem of an overstated rate as costs kept declining.

Nor would there be any sound reason to adopt the staff's suggestion that a limited variable tariff be used. The staff recommends adjusting only three items: "net investment" (most but not all of the components that make up rate base); throughput; and federal and state income tax rates. With the exception of depreciation, as noted above, other costs to be reflected in the rate would not be adjusted, according to the staff, but would remain the same until EPC sought to change its rate if the costs were rising (exhibit 16-1, pp. 13-16; staff's initial brief, pp. 70-72).

This proposed limited methodology is hardly the most direct or least complex way to handle EPC's costs. By picking some but not all of the costs to be adjusted, the staff's approach sets up an arbitrary two-tier system by failing to articulate a standard to determine which costs are or are not to be subject to automatic adjustment.

Moreover, the staff would adjust all major cost categories with the exception of operating and maintenance expenses. This means that approximately 75 percent of EPC's total annual costs, as calculated by the staff, would be automatically adjusted (exhibit 16-3, Schedule Nos. 1B and 1C). The staff has given no reason why it has excluded from this variable methodology the remaining costs, about 25 percent.

There is another element, fairness to EPC, which enters the picture under the staff's proposal to pick and choose costs. Operating and maintenance expenses, in particular, tend to be affected by inflation, likely resulting in an upward spiral of such costs. If the other major cost categories were trending downward, as appears likely, and were therefore causing the rate to be adjusted downward, there would be no persuasive reason to deny EPC the opportunity at the same time to adjust its rate in the other direction if its operating and maintenance expenses were rising.

It would be unnecessary and unfair to compel EPC to file for repeated rate increases dealing with a relatively small proportion, about 25 percent, of its overall costs. The staff's proposed limited methodology is rejected.

The better approach to handle all of EPC's costs, as well as its throughput, would be to prescribe the use of an unlimited variable methodology. All of these items would be adjusted monthly, thereby likely changing EPC's rate each month. None of this information would be filed with the Commission at the time of the monthly adjustments. Instead, EPC would file with the Commission annually, at the end of April, a written report covering the most recent calendar year showing for each month of that year, first, its estimated costs and throughput, and, second, its actual costs and throughput.[10]

A condition would be attached to EPC's monthly variable rate which would make the rate, as noted, subject to refund. The only other obligation imposed upon EPC would be the requirement that it file an annual report, as described above, at the end of each April. Based upon information gleaned from the report, anyone questioning or challenging the variable rate would have the burden to prove that the rate was not just and reasonable. If the burden were carried, however, EPC would pay refunds with interest, as calculated in accordance with the way that the Commission computes interest for other purposes (*See, e.g.*, 18 C.F.R. § 154.305(h)(4) and Commission Docket No. RM77-22, *FERC Statutes & Regulations, Regulations Preambles 1977-1981* at ¶¶ 30,083, 30,099, 30,121, and *FERC Statutes and Regulations, Regulations Preambles 1982-1985* at ¶ 30,412).

That the variable rate would be subject to refund would not make it a suspended rate in any sense. Consequently, there would be no basis to support any notion that the refund condition somehow placed a burden upon EPC to prove that the rate was just and reasonable. So long as EPC continued to use a variable rate, the burden would remain on others to prove that the rate was not just and reasonable.

A refund condition would be prescribed here pursuant to section 15(7) while determining that EPC's proposed initial rate — which itself is being collected subject to refund — must be variable, not fixed, in order for the rate to be just and reasonable. The Commission, as noted, has ample authority to attach such a condition to the rate. *TAPS, supra*, 436 U.S. at 653-57; *Chesapeake & Ohio Ry., supra* 426 U.S. at 509, 513-15; *see also American Trucking Ass'ns, supra*, 467 U.S. at 364-67; *cf. Texaco, Inc. v. FPC*, 290 F.2d 149, 154-56 (5th Cir. 1961). The need for the condition would be to nudge EPC, if it were adjusting its rate automatically each month knowing that it had a green light to pass through the costs it incurred, to try to hold down its costs by operating in an efficient manner.[11]

EPC would deal with the past and the future regarding its variable rate. The past would cover the period from October 2, 1987, when EPC's proposed initial rate became effective subject to refund, until the end of the month in which a final order was issued in this case. The future would start with the first day of the next month after a final order was issued.

For the past, EPC would compare its actual costs, calculated in accordance with the findings of this decision, with the total revenues received for that period based upon the 71 cents per barrel-initial rate. If the revenues exceeded the costs, EPC would pay a refund within 90 days after the end of the month in which a final order was issued in this case. On the other hand, if the costs exceeded the revenues, EPC would charge for this difference within the same 90-day period. Through a so-called compliance filing made with the Com-

[10] With one exception, the first month for the future (as described *infra*), each month's rate would consist of two elements: one, an estimate of the costs and throughput for the immediately preceding month; and two, an adjustment mechanism known as a "true-up" to harmonize a prior month's estimate with the actual costs and throughput for that month (which generally results in a surcharge or refund). Because the actual costs and throughput are usually known within two months after the month has passed, each month's true-up would deal with the month that occurred two months earlier.

Consequently, if EPC filed its annual report for the most recent calendar year showing its monthly estimates of costs and throughput, as well as its actual costs and throughput for each of those months, it would use, say, its February bill to show its January estimate and its March bill to show the actual figures for that January.

[11] A refund can be ordered by the Commission not only where a rate has been suspended subject to refund, but in other instances as well. One example would be where there is a violation of a tariff on file with the agency — such as where a rate is charged which differs from the one listed in the tariff, or where an attempt is made to charge ratepayers for costs not covered by the tariff. *Cf. Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 576-78 (1981); *T.I.M.E. Inc. v. United States*, 359 U.S. 464, 473 (1959); *Lowden v. Simonds-Shields-Lonsdale Grain Co.*, 306 U.S. 516, 520-21 (1939).

As another example, a refund can also be ordered if, after a refund condition has been imposed to protect the public interest, a showing has been made that a rate (albeit not suspended) is not just and reasonable. *Cf. Texaco, supra*, 290 F.2d at 154-56.

mission within the same 90-day period, EPC would show in detail, with supporting workpapers, the calculations for the above determination.

For the future, EPC would bill for the first month in the second month. This bill would be the only one with a single element, an estimate of the costs and throughput for the previous month. Thereafter, for each succeeding month, the bill would consist of two elements: one, an estimate of the costs and throughput for the immediately preceding month; and two, a true-up relating to the month that occurred two months earlier (*See* footnote 10, *supra*).

If a variable tariff were ordered to be used here, EPC would adjust its rate monthly in conformity with the procedure outlined above. However, in view of the Commission's recent determination in *Kuparuk*, *supra*, that the agency lacks the power to order the use of such a tariff, EPC is not required to use a variable tariff in the case at bar.

C

A number of cost questions remain to be decided in three areas. The first area involves EPC's rate base. Most of the questions relate to whether or not the rate base, which in all reasonable likelihood will continue to decline (as explained above), needs to be reduced even more for various reasons. In addition, given the reasonable likelihood of an ever-declining rate base, another question concerns determining the appropriate juncture to price or assess the rate base. Whatever its dollar amount at that point in time, the rate base would then be multiplied against a weighted average rate of return on the debt and equity capital in order to calculate a so-called return allowance to be reflected in EPC's rate.

The second area deals more directly with EPC's return allowance. The allowance is affected in part by EPC's capital structure (i.e., the debt-equity ratio) and the rate of return to be allowed on the company's long-term debt and common equity capital. Questions concerning these subjects have to be resolved.

The third area which needs to be addressed concerns some of EPC's expenses, present or future, as well as the company's throughput that are reflected in its current rate. In particular, there are various questions concerning DR&R, apart from the issue decided above regarding whether to apply the UOT methodology to recover these costs. So long as a variable tariff is not ordered to be used here, there are a few other matters which will have to be decided.

1. Rate Base

Alaska and the staff contend, albeit for different reasons, that EPC's rate base should be lowered. The company disputes these contentions.

(a) Overhead costs, also known as indirect costs, cannot be attributed directly to a specific activity, facility, or piece of hardware (Tr., *e.g.*, 536). Alaska, but not the staff, contends that about $2.9 million of the Endicott project's overhead costs have been improperly included in EPC's rate base.

According to Alaska, about $2.5 million of this total should have been assigned to the project's production function, not its transportation or pipeline function, in accordance with an allocation process or arrangement which the Endicott partners had worked out for costs shared by the production and transportation functions. Alaska goes on to argue that the remaining balance, about $.4 million, deals with the project's oil wells and, thus, also should have been assigned to the production function, rather than the transportation function. Alaska's arguments are rejected.

With regard to the $2.5 million, Alaska advances a rather labored, esoteric argument. The argument seems to boil down to an assertion that the Endicott partners have irrevocably bound themselves by a "completion agreement," especially exhibit B appended thereto (exhibit 1-4), to assign overhead costs to the transportation function in accordance with "conceptual ratios/formulas" (Initial brief, p. 36) which cannot be changed and which are contained in two underlying documents: pipeline allocation tables (exhibit 3-16) and a facilities description paper (exhibit 13-2.2).

Contrary to Alaska's assertion, the completion agreement does not indicate in any way that the partners have locked themselves into unalterable ratios/formulas spelled out in the documents mentioned to assign overhead costs. In fact, the agreement specifically recognizes that the partners have preserved their rights to question and perhaps change, among other matters, the assignment of costs to the production or transportation functions (exhibit 1-4, pp. 7-9).

The fact that one of the underlying documents, the facilities description paper, states that it is referenced in the completion agreement and serves as the basis to divide or assign costs between the production and transportation functions (exhibit 13-2.2, p. i (Bates No. 00052)) is not inconsistent with the findings above. That a document is the foundation of an agreement scarcely means that conclusive weight must be given to the document in all instances or that no other data may be relevant to construe the agreement.

EPC states, and there is no reason to question the fact, that yet another document known as the project allocation table (exhibit 13-10) also has been used by the Endicott partners to assign overhead costs to the production and transportation functions. Though Alaska asserts that the partners never formally adopted this document, it has failed to show why that inaction was critical or how, in fact, the partners ever formally adopted the other two documents and made them conclusive.

Far more important is the fact that the Endicott partners were dealing for years, during the preconstruction and construction stages, with estimated costs which could affect the allocations between the production and transportation functions. Once actual costs were known, and a harder look was given as to which costs should be assigned to which function, it is not surprising that some adjustments had to be made.

For example, EPC points out that while the earlier documents had assigned certain general engineering and management overhead costs to the transportation function, the Endicott partners later discovered that it was error to have included such costs. Thus, through the project allocation table the error was corrected, resulting in an adjusted reduction to EPC's rate base of about $1.1 million (exhibit 3-11, at pp. 11-13).

On the other hand, EPC indicates that the partners also discovered the earlier documents failed to assign certain overhead costs associated with North Slope craft manhours to the transportation function. When this omission was corrected through the later project allocation table, it caused an adjusted increase to EPC's rate base of about $3.7 million (exhibit 3-11, at pp. 13-18). The $3.7 million increase, offset against the $1.1 million reduction noted above, plus two other adjusted reductions to the rate base of about $.1 million, resulted in a net addition to EPC's rate base of about $2.5 million (exhibit 13-5).

There is no rational basis to prohibit EPC from adjusting its rate base upward by the $2.5 million. The Endicott partners, after all, at earlier stages had estimated the capital costs of the pipeline to be substantially above the actual, final costs of about $55.7 million (exhibit 3-0, p. 9; exhibit 3-10; exhibit 4-0, p. 5). Certainly, Alaska has given no indication that it wants EPC to be using the earlier, higher cost estimates to determine the company's rate base. Consequently, there is no sound reason to lock EPC into cost-allocation estimates to assign overhead costs.

With regard to the remaining balance of about $.4 million, which deals with general engineering and management overhead costs, Alaska claims that this amount is related to the Endicott oil wells and, thus, none of it should have been assigned to the project's transportation function (exhibit 13-0, pp. 37-43). EPC, on the other hand, states that out of the total costs covering the project's general engineering and management overhead, almost 96% has been assigned to the production function (whether or not it specifically relates to the wells), and only the remainder of about 4% has been assigned to the transportation function (exhibit 3-11, pp. 21-22; *see also* exhibit 3-10).

By not challenging or refuting EPC's statement, Alaska has failed to show that the Endicott partners should have assigned even more of these overhead costs to the production function. There is no reasonable ground to remove the $.4 million from EPC's rate base.

(b) Environmental monitoring obligations have been imposed upon the offshore Endicott project by the U.S. Army Corps of Engineers (exhibit 2-20). The Endicott partners have divided these costs, about 78%-22%, between the production and transportation functions, respectively (exhibit 3-11, pp. 26-28). The staff, but not Alaska, challenges this allocation, claiming that too many environmental costs have been assigned to the transportation function. A more appropriate division of the costs, according to the staff, would be about 89% for production, 11% for transportation (exhibit 18-1, pp. 11-14; exhibit 18-8).

The staff's argument would have the effect of lowering EPC's rate base as well as the operating and maintenance expenses to be reflected in the company's rate. Prior to the commencement of EPC's operations, the project's environmental monitoring costs were capitalized by the Endicott partners — i.e., cost-recovery was deferred and spread over a number of years. Thus, these costs have been included in EPC's rate base (exhibit 3-11, p. 26). The staff's argument would effectively reduce the rate base by about $700,000 (*Compare* exhibit 3-11, p. 26, *with* exhibit 16-1, p. 10).

After EPC's operations began, the partners elected to expense rather than to capitalize the environmental costs (exhibit 3-11, p. 26). Thus, beginning with October 1987 the costs have been recovered immediately, presumably through monthly billings. For 1988 alone, the staff's argument would effectively reduce EPC's environmental expenses and, consequently, its rate by about $765,000 (*Compare* exhibit 3-11, p. 26, *with* exhibit 16-1, p. 10, and exhibit 16-2, Schedule No. 1B).

For the reasons that follow, the staff's argument is rejected. EPC can continue to divide the project's environmental monitoring costs between the production and transportation functions by using the same ratio that it has been applying.

As an offshore venture, the Endicott project consists of various manmade facilities, including two production islands and two causeways. One causeway runs perpendicular between the shore and an interconnection point with the second causeway, which links the two islands (*See* Fig. 2 appended to exhibit 2-20). The causeways have been built with gravel.

The Endicott partners and the staff agree that the gravel costs should be the basis used to allocate the environmental costs. But to determine EPC's share, the partners limit the costs to those associated with the first causeway only, between the shore and the interconnection point with the second causeway (exhibit 3-11, p. 26). The staff, on the other hand, includes not only those costs, but the gravel costs associated with the second inter-island causeway as well (exhibit 18-1, p. 13).

The reason that the partners take a more limited approach is because they claim that the first causeway is the primary basis for the environmental monitoring costs. According to the partners, if this causeway running perpendicular to the shore had no breaks or breaches in it, a dead-end effect would be produced which would cause an adverse environmental impact upon water circulation, chemistry, and fish passage in the Beaufort Sea. Consequently, the Corps of Engineers ordered two breaches — 200 and 500 feet in length, respectively — to be made in this causeway, while reserving the power to order a more lengthy breach to be added in the same causeway at a later time, depending upon the effectiveness of the first two breaches in mitigating the environmental concerns (exhibit 3-11, pp. 27-28; Tr., *e.g.*, 340-41).

The staff does not dispute Endicott's statement that the first causeway is the primary reason for the project's environmental monitoring costs. Instead, the staff focuses on the fact that the Corps of Engineers is concerned about the Endicott project's environmental impact upon a broad study area sweeping well beyond the project itself to the west, east, and north (exhibit 2-20, p. 3, and Figure 2 appended; exhibit 18-1, pp. 12-13). Consequently, the staff contends that it is appropriate to include the gravel costs associated not only with the first causeway, but with the second causeway as well, to determine an allocation ratio for EPC's share of the environmental monitoring costs (*id.*).

The staff's argument proves too much. An examination of the environmental study area shows, for example, that it even covers Prudhoe Bay, which contains massive oil reservoirs dependent upon TAPS for transportation. *TAPS, supra*, 436 U.S. at 634. The staff has neither shown nor even suggested that the Endicott partners are to be financially responsible for any environmental impact upon Prudhoe Bay despite its being part of the Endicott study area.

The Endicott partners have made enough of a showing to establish that the first causeway, between the shore and the interconnection point with the second inter-island causeway, is in fact the primary cause for the environmental monitoring costs being incurred by the Endicott project. There is, consequently, a reasonable basis to adopt the partners' method, rather than the staff's proposed method, to allocate the costs between the production and transportation functions. Endicott's method is far from arbitrary, as can be seen by the fact that more than three-fourths of the environmental costs are still assigned to the production function. The ratio that Endicott is to continue to use is 21.89% for transportation.

(c) During the construction period of a project like an interstate oil pipeline, there is usually no current charge to ratepayers for the associated costs. Once service begins, these pre-operational costs are included in rate base and a charge starts to be assessed for them.[12]

Among the pre-operational costs is an "allowance for funds used during construction" (AFUDC). This represents a return allowance which accrues or accumulates on the debt and equity capital used during construction.

Alaska contends that EPC's AFUDC, as now reflected in the company's rate base, is too high for various reasons. The staff joins EPC with regard to one of these reasons, sides with Alaska as to another reason, while quarreling with both the state and EPC concerning two other reasons. It is concluded that EPC must reduce its rate base because of its treatment of AFUDC.

Construction of the Endicott pipeline began in 1985 before EPC was formally created. When EPC was later established in 1986 and charged with the task of both completing construction and operating the pipeline, it paid in December 1986 about $31 million to the parent which had borne these pre-operational costs. Included in the $31 million-total was an item, labeled interest, of about $1.6 million for the carrying charges on the funds expended during construction prior to the transfer of responsibility from the parent to EPC (exhibit 3-7).

[12] The charge will include a return allowance on the rate base's outstanding balance. The charge also will include a depreciation-component to recover the debt and equity capital invested.

It is that $1.6 million in carrying charges which Alaska contends should have been treated as AFUDC. EPC does not refute Alaska's argument. Nevertheless, after first limiting the AFUDC amount as Alaska has done (exhibit 3-7; Tr. 2058-62), EPC later revised its approach and increased the amount to about $2.98 million (exhibit 4-4.7). It did so by piggybacking on a technique used by the staff, which technique — albeit not producing quite as high a number as EPC's revision — still inflates the company's AFUDC (exhibit 19-2; Tr. 2060-62).

Even though the staff claims that it has used the same technique in other oil pipeline cases — i.e., ignoring the actual carrying charges paid by an affected company and substitute a hypothetical number —, it has failed to prove that the higher, hypothetical substitute is reasonable. Where a company has incurred actual costs, it is far better to use those costs for ratemaking purposes. EPC should not benefit from a hypothetical approach that has not been shown to be sound. In addition, the company is to use the actual date paid, not an earlier "cash call" date, to calculate its AFUDC (Tr. 2063-64).

There is a second reason why EPC's AFUDC is too high. EPC treats the AFUDC as though it compounds monthly (exhibit 4-4.7). Alaska and the staff, on the other hand, treat the AFUDC as though it compounds semiannually only, thereby producing a lower AFUDC amount than EPC's calculation (exhibit 12-0, p. 14; exhibit 19-1, p. 6).

The compounding methodology used by Alaska and the staff is correct. The Commission has been using the semiannual approach for years to calculate AFUDC with regard to other regulated entities, and EPC has failed to explain why an oil pipeline should be treated differently (*See* 57 FPC 608, 612, *reh'g denied*, 59 FPC 1340, 1344-45 (1977); Tr. 594).

In view of the fact that a TOC methodology has been rejected in this case, there is no need to address a couple of other AFUDC issues which Alaska has raised (Initial brief, p. 45 n.156). The final AFUDC amount is, of course, dependent upon such questions as the appropriate debt-equity ratio for EPC and the reasonable rate of return to be allowed on the company's common equity capital. It is here where the staff quarrels with both EPC and Alaska. These questions will be resolved below.

(d) EPC agrees with Alaska and the staff that its rate base needs to be reduced because of an account known as "accumulated deferred income taxes" (ADIT). However, for part of 1987 (beginning in October when the Endicott pipeline went into service) extending into part of 1988, there is a disagreement as to whether the reduction should have been for a larger amount or balance, as Alaska and the staff contend, or only part of that amount, as EPC asserts. Alaska's and the staff's position is sustained.

As a partnership, EPC itself does not pay income taxes. The tax consequences of EPC's operations are passed through to its respective parents which have formed the partnership.

Since October 1987 when the pipeline went into service, EPC has been depreciating its facilities at a much more accelerated pace for income tax purposes than for ratemaking purposes, even with the use of a UOT methodology. Consequently, for ratemaking purposes in the earlier years while EPC is still enjoying the benefits of accelerated depreciation for income tax purposes, EPC's rate reflects a higher amount of income taxes to be paid than at that juncture is actually paid to government taxing authorities (*see* exhibits 4-5.5 and 4-5.9). This is because, under a "tax normalization" methodology which this Commission uses, there is less depreciation to be deducted from revenues for ratemaking or "book" purposes than is the case for income tax purposes. *See, e.g., FPC v. Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973); *Memphis Light, Gas & Water Division v. FERC*, 707 F.2d 565, 568 (D.C. Cir. 1983).

To keep track of this difference in taxes (for ratemaking as contrasted with actual income tax purposes), an ADIT account is used. While the balance in this account will continue to grow so long as tax depreciation exceeds the ratemaking or book depreciation, the balance will start to decrease when the book depreciation exceeds the tax depreciation. The balance eventually will "zero out" or disappear altogether when the single-asset Endicott pipeline is completely depreciated for ratemaking purposes.

Generally, the Commission requires a regulated company's ADIT balance to be subtracted from rate base (*see, e.g.*, 18 C.F.R. § § 35.25(b)(2) and 154.63a(b)(2)). This is because ADIT represents cost-free capital, not contributed by the shareholders, which is available for use by the company. Given the fact that, through tax normalization, ratepayers bear the burden of a greater income tax allowance than is at that time due to be paid to government authorities, the agency's view is that the ratepayers should receive the benefit of their higher payments through a reduction to rate base so that the company does not earn a return (which essentially reflects a cost of capital) on the cost-free funds. (*See* Order No. 144, *FERC Statutes & Regulations, Regulations Preambles 1977-1981* ¶ 30,254, at p. 31,558 (1981), *reh'g denied*, Order No. 144-A, *FERC Statutes & Regulations, Regulations Preambles 1982-1985* ¶ 30,340, at p. 30,138 (1982), *aff'd sub nom., Public Systems v. FERC*, 709 F.2d 73, 83 (D.C. Cir. 1983)).

EPC, as noted, does not quarrel with the fact that ADIT should reduce its rate base. However, based upon its interpretation of the Commission's "stand-alone" policy as set forth in *Columbia Gulf Transmission Co.*, 23 FERC ¶ 61,396, at pp. 61,857-60 (1983), *aff'd sub nom., City of Charlottesville v. FERC*, 774 F.2d 1205 (D.C. Cir. 1985), *cert. denied*, 475 U.S. 1108 (1986), EPC contends that it only has to reduce its rate base by part of the ADIT for portions of 1987 and 1988. According to the company, this is because during its initial year of operation the tax deductions due to accelerated depreciation exceeded the revenues generated by the company so that it did not record as ADIT the portion of depreciation which had been unused (Tr. 611-12; exhibit 5-1, p. 6; *see also* Tr. 2012).

Alaska and the staff challenge EPC's interpretation of the Commission's stand-alone policy. They are correct in doing so. EPC must reflect as ADIT and thus reduce from rate base the entire difference between tax depreciation and book depreciation for 1987-1988.

In *Columbia Gulf*, the Commission specifically addressed a hypothetical situation which is the precise question presented in the case at bar. As the Commission explained, if it is the regulated entity whose rate is being examined, and it is the one (rather than other affiliates) producing excess deductions, then the entity must immediately reduce its rate base by the tax effect of the entire excess, the ADIT (23 FERC at pp. 61,858-59). This is the stand-alone principle which the Commission has adopted (*id.* at p. 61,860).

Nor is it right for EPC to suggest that in 1987-1988 it had any unused deductions. The fact is that EPC's parents received the immediate benefits of EPC's "excess" deductions through the lowering of their respective taxes (Tr. 611; 723).

This is not the first case where the Commission has dealt with the question of whether a regulated entity must reflect in its rate the entire tax savings generated by so-called excess deductions. In *Trunkline LNG Co.*, 45 FERC ¶ 61,256, at pp. 61,781-83 (1988), *aff'd, Trunkline LNG Co. v. FERC*, 921 F.2d 313, 320 (D.C. Cir. 1990), the Commission has been upheld in ordering the entire tax savings to be reflected in the rate. EPC must do the same here.

There is no need to resolve an additional question concerning ADIT, whether it should be deducted before or after trending the equity rate base, in view of the fact that a proposed TOC methodology has been rejected in this case.

(e) At times, a regulated company's rate base is increased by a "working capital" allowance to reflect the money which the company itself puts up or advances on a short-term basis to finance the service provided until it is compensated or reimbursed by its customers. EPC claims a working capital allowance of $306,000 for 1987 and $438,000 for 1988 (exhibit 4-5.1).

The staff seems to agree that EPC's rate base should reflect some amount as a working capital allowance — at least for 1988, but not for 1987 (*see* exhibit 16-4, Schedule No. 4A & B, p. 1). However, in the staff's view the amount should be less than half of what EPC seeks, about $141,000 (*id.* at p.2).

Alaska, on the other hand, contends that EPC has failed to prove it is entitled to a working capital allowance for any year. Alaska is correct. EPC must eliminate any such proposed allowance from its rate base.

EPC does not even suggest that it presented adequate evidence justifying a working capital allowance. Instead, it relies on what is alleged to be a rule of thumb which the Commission automatically allows in every case where a regulated company does not present specific evidence to support such an allowance. According to this so-called rule, a company is permitted to claim as its working capital allowance one-eighth of its total operating and maintenance (O&M) expenses — sometimes referred to as a 45-day rule. As EPC views this matter, it is not overreaching because it is seeking an allowance of only one-twelfth, rather than a larger one-eighth, of its total O&M expenses (exhibit 4-6, p. 34).

Contrary to EPC's assertions and intimations, the Commission has no blanket rule on this subject covering every industry that the agency regulates. Rather, at the present time the Commission treats the natural gas and electric utility industries differently, applying a 45-day rule in one industry but not the other.

Under the Commission's present regulations, a natural gas company is presumed to be entitled to no working capital allowance at all unless it adduces hard evidence justifying such an allowance (*see* 18 C.F.R. §§ 154.63(f), Statement E, and 154.63b). On the other hand, notwithstanding the Commission's rather murky regulations presently applicable to electric utilities, in the absence of compelling evidence to the contrary, a one-eighth or 45-day rule is used, subject to possible downward adjustment, thereby permitting a utility to receive a working capital allowance (*see FERC Statutes and Regulations* ¶ 32,478 (1990) (termination order of proposed rulemaking on calculation of cash working capital allowance for electric utilities); *Carolina Power & Light Co.*, 6 FERC ¶ 61,154, at pp. 61,295-96 (1979), *aff'd on other grounds sub nom., ElectriCities of North Carolina v. FERC*, 708 F.2d 783 (D.C. Cir. 1983)).[13]

Whatever the Commission's reasons for using different standards on the natural gas and electric sides regarding a working capital allowance, EPC has made no effort to show why it, an interstate oil pipeline, should be treated the same as an interstate electric utility or different from an interstate gas pipeline. Moreover, EPC lumps together various components which make up working capital — such as materials and supplies, prepayments, and cash working capital (exhibit 1-8.6, at p. 4; *see also* 18 C.F.R. § § 35.13(h)(12)(i)-(ii) and 154.63(f), Statement E). Yet, even on the electric side, a 45-day rule applies only to cash working capital, not the other components (*See, e.g., Carolina Power & Light Co., supra*, 6 FERC at pp. 61,295-96).

The Commission itself observed in *Williams* (pre-*Farmers Union* II), which it reaffirmed after judicial review (31 FERC ¶ 61,377, at p. 61,838), that the cash working capital requirements of oil pipelines are "minimal" (21 FERC ¶ 61,260, at p. 61,704 n.386). In these circumstances, there is simply no reasonable ground for EPC to claim that it can sit back, choosing to present no evidence on cash working capital, and still expect to receive an automatic allowance which increases its rate base.

Nor has EPC proved that it is entitled to a working capital allowance for such other components as materials and supplies or prepayments. EPC has not refuted Alaska's statements that the company's books and records show a "zero level of investments in materials and supplies" for either 1987 or 1988 (exhibit 13-0, p. 47). As for prepayments, EPC has not denied Alaska's contentions that two items — property taxes and right-of-way rentals—which at first blush appear to be prepayments made by the company are, in effect, offset by tariff charges which the company collects from its parent-customers and accrues in advance of its own payments (*id.* at pp. 48-49).

Though the Commission's staff has taken the position that EPC should receive a working capital allowance for 1988, limited to prepayments, it has been unduly generous to the company. The staff has not shown why EPC should receive such an allowance. Nor has it paid enough attention to Alaska's arguments or EPC's failure to rebut those arguments.

(f) The final question concerning EPC's rate base is determining the appropriate juncture to price or assess that dollar amount. If EPC were required to adjust its rate monthly, the company's rate base would be assessed by averaging the amount at the beginning and the end of each month.

As noted, there is a reasonable likelihood that EPC's rate base will continue declining. Consequently, it serves the company's interest to contend, as it does, that the rate base should be assessed earlier rather than later so that its return allowance will be higher. Alaska and the staff, on the other hand, argue for some type of averaging procedure to assure that the rate base and, thus, the return allowance are not overstated.

An averaging technique would be a more reasonable approach where a company's rate base is declining. To track the monthly cost changes that would occur, EPC would average the rate base monthly rather than annually.

It is recognized that certain rate base items, such as ADIT, could not be determined with precision each month. EPC would be expected, however, to approximate such items with reasonable accuracy based upon experience gained as reflected, for example, in past tax returns filed by its parents.

Because a variable tariff cannot be ordered to be used in this case as a result of the Commission's recent determination in *Kuparuk, supra*, another method needs to be used to assess the rate base. To assess EPC's rate base at a specific point in time, in effect taking a snapshot of it at a particular juncture, will not be reflecting reality given the fact that this dollar amount is ever declining. Nevertheless, for purposes here in order to calculate its return allowance, EPC is to use whatever the company's rate base was on December 31, 1988.

[13] On their face, the regulations seem to call for an electric utility to provide enough information about the timing of its cash advances and reimbursements in order for the Commission to determine whether a working capital allowance will be permitted (*see* 18 C.F.R. § 35.13(h)(12)(ii)). What the regulations do not state is that even in the absence of such information, as well as any evidence to the contrary, the Commission nevertheless will apply a 45-day rule as described above.

The Commission should clarify its regulations so that the public, including reviewing courts, is not misled. *See, e.g., Boston Edison Co. v. FERC*, 885 F.2d 962, 971 (1st Cir. 1989), where the First Circuit believed that the Commission had revised its regulations imposing a greater burden upon an electric utility to justify a working capital allowance, but that such revised regulations did not apply in the circumstances of the case.

2. Return Allowance

EPC's return allowance is intended to compensate the company, after taxes have been paid, for such costs as obtaining and making use of debt and equity capital. In addition to the rate base questions decided above, EPC's return allowance will be affected in part by the company's capital structure as well as the rate of return to be allowed on the company's long-term debt and common equity capital.

(a) A regulated company's capital structure, its debt-equity ratio, can materially influence its return allowance. Part of the reason is that, for ratemaking purposes, common equity is deemed to be a greater financial risk than either debt or preferred equity capital and, thus, is entitled to earn a higher return.

The greater risk arises from the fact that debt and preferred equity each outranks common equity with regard to a regulated company's earnings and assets. Bondholders have the highest claim on the company's earnings (for repayment of all related debt costs) and, in the event of the company's insolvency, on its remaining assets. If there is any preferred stock, it has the next highest claim with respect to dividends to be received and, if the regulated company were liquidated, whatever assets remain after bondholders have been satisfied.

While a written promise for these payments or entitlements is given by the regulated company to bondholders and any preferred shareholders, no such written commitment is made to common shareholders. The latter have the lowest claim to dividends (if such payments are made at all) and, in the event of the company's bankruptcy, to the remaining assets.

There is another reason why, in addition to the return allowance, common equity capital inflates a regulated rate. Income taxes are owed on the return for equity capital only, not for the debt capital which generates tax-deductible interest. Accordingly, for ratemaking purposes, an income tax component needs to be reflected in the rate to assure that the company is made whole for its equity capital after taxes have been paid.

For ratemaking purposes, there is a strong incentive for a regulated company to seek the highest common equity ratio possible. Conversely, those advocating a lower rate attempt to hold down the same ratio as much as possible.

In the present case, it is not surprising that among the three parties EPC seeks for itself the highest common equity ratio, 70%, with a debt ratio of 30%. Nor is it surprising that Alaska, conversely, recommends for EPC the lowest common equity ratio, 30%, with a debt ratio of 70%. The staff, on the other hand, urges that EPC's debt-equity ratio be divided evenly, 50%-50%. The staff makes this recommendation even though its own presentation shows an average common equity ratio for a group of oil pipelines, which it regards to be comparable to EPC, of 56.5% (exhibit 15-1, p. 7; exhibit 15-2, p. 7).

These disparate proposals merely underscore the fact that EPC does not have its own capital structure, as the company acknowledges (exhibit 4-7, p. vi; Initial brief, pp. 13-14 and 19-20). This means that EPC does not issue its own debt, nor is its stock traded publicly. Thus, every party, even the company itself, is recommending the use of a hypothetical capital structure for EPC.

EPC arrives at its proposed hypothetical structure of 70% equity, 30% debt by taking the actual capital structures of its respective parents at the time EPC itself (i.e., the partnership) was formed in October 1985, weighted by their respective ownership shares (exhibit 4-7, pp. vi and 23, and "Exhibit 10" appended to the document). According to EPC, it has used its parents' capital structures because the Commission in *Williams* (post-*Farmers Union* II) ordered that this approach be taken.

While the Commission in *Williams* (Opinion No. 154-B) seemingly announced that it would use the actual capital structure of an oil pipeline or its parent for calculating a return (31 FERC at pp. 61,833 and 61,836), it went on to qualify the announcement. It would "allow participants on a case-specific basis to urge the use of some other capital structure" (*id.* at p. 61,833).

Taking the Commission at its word, Alaska urges that a different hypothetical structure be used for EPC because the parents' own structures, given the diversity of the parents' operations, do not accurately reflect the limited pipeline operations of EPC. In Alaska's view, EPC could have borrowed 70% of its total capital requirements if it had not been affiliated with the Endicott producers because the producers, in turn, would have been willing to give so-called throughput guarantees to the "independent" pipeline in order to secure lower transportation rates. Because interest payments on debt are allowed to be passed through a rate, Alaska sees a 70% debt as being attainable and not posing a financial risk to a regulated entity like EPC (exhibit 14-0, pp. 55-68).

Alaska is right to question EPC's proposed use of its parents' capital structures as a proxy for its own structure. But it has failed to justify a 70% debt ratio for the pipeline. Alaska's theory is laden with too much conjecture. The theory also leads to a dubious conclusion that virtually any regulated entity's capital structure can consist almost entirely of long-term debt. Any business enterprise, whether regulated or not, can be courting financial problems if it is too highly leveraged (*Cf.* Tr. 1516; 1903-19).

The staff, on the other hand, while agreeing with Alaska that EPC's parents' capital structures should not be used as a proxy here, takes a position in the middle of the two extremes urged by EPC and Alaska. Its recommendation of 50% equity, 50% debt somehow stems from examining the ratios of two discrete groups — one consisting of oil pipelines, the other of natural gas pipelines. According to these figures, the oil pipelines' average common equity ratio, as noted, is 56.5%, while the natural gas pipelines' average common equity ratio is 38.7%. From this range of figures, the staff somehow reached its conclusion (exhibit 15-1, pp. 7-8; exhibit 15-2, pp. 7-8).

The Commission has great discretion in setting a capital structure for a regulated entity like EPC which does not issue its own debt or have its stock traded publicly. But there is no sound reason to use here the capital structures of EPC's respective parents as a proxy for the company in view of the fact that the parents' business operations and risks are so varied and, thus, so different from EPC's limited pipeline operations (exhibit 6-7, pp. 16-17; Tr. 775 and 802).

EPC claims that because it is a single-asset enterprise whose business risks are much greater than those of its diversified parents, it is acting conservatively by using its parents' capital structures (Tr. 826). But not every single-asset enterprise is always more risky than diversified businesses. Diversification into a number of chancy operations does not make an entire business less risky than a single enterprise which enjoys enough, steady income annually. EPC has failed to present adequate evidence demonstrating that its business risks are greater than those of its parents, especially where it has been shown that the parents' operating income (*i.e.*, profitability) is heavily dependent upon such a high-risk venture as exploration and production of fossil fuels like oil and natural gas (Tr. 1140; exhibit 15-2, pp. 1-4).

Notwithstanding EPC's assertions, the Commission never declared in *Williams* (Opinion No. 154-B) that whenever a subsidiary does not have its own capital structure, a parent's capital structure is to be used as a proxy in all instances. Apart from the fact *Williams* expressly invited parties on a case-by-case basis to urge the use of some other capital structure, *Williams* only alluded to a situation where there is a single parent and never addressed how to determine a capital structure where, as here, there are multiple parents forming a partnership.

With so little guidance to determine a reasonable hypothetical capital structure for EPC, it is evident that any conclusion reached on the subject can be assailed. Nonetheless, given the fact that none of the proposals of EPC, Alaska, or the staff has been justified, it is concluded that the most reasonable solution is to use for EPC the average common equity ratio which the staff derived from its group of so-called comparable oil pipelines, 56.5%, leaving a hypothetical debt ratio for the company of 43.5%.

(b) Part of EPC's return allowance will hinge upon the company's cost of long-term debt. Because EPC does not issue its own debt, there are no specific debt instruments which can be examined to determine the company's cost. Consequently, a hypothetical cost for this capital needs to be determined.

EPC uses 10.5% as its cost (exhibit 8-0, p. 6). Alaska, but not the staff, challenges this proposed number as being too high. According to Alaska, the number should be 9.21% (exhibit 14-37).

Alaska's argument is rejected. EPC can continue to use 10.5% as its hypothetical cost of long-term debt.

For its proxy, EPC looked to long-term corporate bonds issued in 1987 around the time that the pipeline went into service. It selected those that were highly rated and thus of lower cost, AA, showing an average rate of 10.5% (exhibit 8-0, p. 6; exhibit 8-2).

Alaska, on the other hand, started by using long-term debt issued in 1985 around the time that the Endicott partnership was formed. It picked corporate bonds with a lower rating and thus a higher cost, Baa, showing an average rate of 12.5% (exhibit 14-0, p. 105). Alaska then adjusted this rate downward by 3.29%, thereby eliminating an "interest rate risk premium" and arriving at a rate of 9.21% (exhibit 14-37, p. 2).

The premium, also sometimes referred to as a "liquidity preference premium" (Alaska's initial brief, p. 32), is supposed to compensate a lender for tying up its money on a long-term basis. By removing the premium, Alaska produced a rate for short-term debt (exhibit 14-35; Tr. 1841-44; 1928-33).

There may have been reasons apart from the question presented here which prompted Alaska to come up with a cost for short-term debt. EPC, for example, points out that Alaska's estimated cost for long-term debt incongruously exceeds its estimated cost for common equity (*Compare* exhibit 14-0, p. 105, *with* exhibit 14-37, p. 3; *see also* Tr. 1522-31).

No matter what Alaska's reasons to show a cost for short-term debt, it is the cost of long-term (not short-term) debt which is an important component in calculating a return allowance for a regulated company like EPC. Alaska's unsupported recommendation is rejected. EPC's proposed cost for its hypothetical long-term debt is reasonable and is hereby adopted.

(c) The remaining question that needs to be decided in order to compute an overall rate of return and, thus, a return allowance for EPC is the cost of the company's common equity capital. When this question arises in a contested proceeding conducted by this Commission, it is not unusual for the regulated company whose proposed rate is being examined to recommend a higher rate of return on common equity than the other parties. Such is the case here.

EPC is proposing for itself a nominal rate of return of 15.5% (exhibit 4-0, pp. 15-16; exhibit 4-5.3; exhibit 6-0, pp. 14-15; exhibit 9-0, p. 22). However, the company suggests that even this number might be too low and could be increased by another two percentage points (exhibit 10-0, p. 5). Compared to EPC, the staff proposes a nominal rate of 13.0%, which it would reduce to 12.0% if a variable cost-tracking tariff were required to be used here (exhibit 15-1, p. 14). Alaska, on the other hand, proposes the lowest rate of return on common equity for EPC, a nominal rate of 11.8% (exhibit 14-37, p. 3).

Because a TOC methodology has been rejected in this case, only a nominal rate (not a real rate) will be determined. If a variable tariff were ordered to be used here, it might well be better to set a fluctuating rate of return on equity for EPC, rather than to fix a single rate which would remain the same year-after-year even as economic conditions changed. *Cf. Bluefield Water Works & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679, 693 (1923). However, in view of the Commission's recent decision in *Kuparuk, supra*, no variable tariff and no fluctuating rate of return will be used.

The staff's presentation, though more reasonable than the presentations of EPC or Alaska, could be more complete. Nevertheless, because the record does not permit an entirely discrete analysis to be made, the staff's presentation will have to be adopted as modified below. While the resulting rate of 13.7% is based upon the record, it does not pretend to be mathematically exact. As the presiding judge has observed in various decisions including *Midwestern Gas Transmission Co.*, 27 FERC ¶ 63,073, at p. 65,291 (1984), *aff'd*, 31 FERC ¶ 61,317 (1985), setting a reasonable rate of return on common equity capital is — in the words of the now-defunct Federal Power Commission — "a matter of judgment which cannot be reduced to mathematical proportions and which cannot be made to turn upon a formulistic computation . . . ." *Midwestern Gas Transmission Co.*, 32 FPC 993, 1000 (1964). A rate of return on common equity capital is not and cannot be determined by the slide-rule. *Cf. Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945).

In starting the analysis of determining a reasonable rate of return, it helps to emphasize the standards laid down years ago by the Supreme Court in the oft-cited *Bluefield, supra*, 262 U.S. at 692-93 and *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). As these cases found, a reasonable rate of return assures investor confidence in the financial soundness of a regulated entity, while enabling the entity to maintain its credit, attract capital for the proper discharge of its public duties, and earn a return commensurate with that being earned by other businesses facing corresponding risks.

The staff began by making what is known as a discounted cash flow (DCF) analysis. The Commission looks with favor upon such an evaluation to set a rate of return on common equity. The analysis tries to determine the current cost of equity by adding the present market dividend yield on common stock of a particular company with the future growth rate in dividends as anticipated by investors.

Because EPC's stock is not traded publicly, the staff needed to select a proxy. It is hardly surprising that the staff turned away from using the stock of EPC's respective parents given the fact, as noted, that the parents' business operations and risks are so varied and, thus, so different from EPC's limited pipeline operations.

The staff picked for its proxy a group of natural gas pipelines whose stock is traded publicly and whose operating characteristics it deemed to approximate most closely the characteristics of an oil pipeline like EPC. For the dividend yield of each pipeline (the annual dividend per share divided by the average monthly price per share), the staff used the then-most recent data available covering a six-month period extending through November 1988. This produced a range of dividend yields representing the group of pipelines. (exhibit 15-2, pp. 27-32.)

The staff also estimated the growth rates for each of the pipelines. It arrived at these numbers by using projections made by Value Line and Institutional Broker Estimate System (IBES), separate investment advisory services. As the Commission favors, the staff used the growth rates to make an upward adjustment to its dividend yield-calculations to recognize the fact that an annual dividend is usually paid out in quarterly increments, rather than all at one time. (exhibit 15-2, pp. 26 and 33; *New England Power Co.*, 22 FERC ¶ 61,123, at p. 61,188 (1983)). The staff then added the estimated growth rates to the dividend yields for each of the companies, thereby calculating a range of rates of return on common equity from 12.82% to 15.6% (exhibit 15-1, p. 13; exhibit 15-2, p. 26).

Because its analyses until then had revolved around the group of gas pipelines, not EPC, the staff then compared the financial and business risks of the group, on the one hand, and EPC, on the other. It concluded that EPC was of lower risk than the group average. Consequently, it proposed a nominal rate of return for EPC of 13.0%, which was toward the lower end of the group's range. (exhibit 15-1, pp. 10-13).

To show that its 13% proposed rate was reasonable and not too low from EPC's standpoint, the staff pointed to the fact that during 1988 the average yield on long-term (10- or 30-year) U.S. Treasury bonds was about 9%. Because these are considered to be the most risk-free debt instruments, the staff suggested that its proposed rate for EPC's equity implicitly contained a so-called risk premium of about 4%, which would be quite generous to EPC because it would be a higher premium than that usually allowed by the Commission (exhibit 15-1, p. 14).

Certainly the staff was right to use six months of data for dividend yields. *See, e.g., Orange and Rockland Utilities, Inc.*, 44 FERC ¶ 61,253, at p. 61,952, *modified on other grounds*, 45 FERC ¶ 61,252 (1988); *Boston Edison Co.*, 42 FERC ¶ 61,374, at p. 62,093 (1988). But it did not use historical data for the growth rates despite the Commission's preference for the use of such data in combination with projections. *See, e.g., Middle South Services, Inc.*, 16 FERC ¶ 61,101, at p. 61,222 (1981); *Boston Edison Co.*, 34 FERC ¶ 63,023, at p. 65,087 (1986)(Initial Decision), *aff'd in pertinent part*, 42 FERC ¶ 61,374, at p. 62,093 (1988).

Moreover, the staff did not explain why it refrained from doing a DCF analysis of a group of oil pipelines, even though it seemed to use the group as a substitute for EPC to compare the risks of its group of gas pipelines with EPC (*see* exhibit 15-1, pp. 10-12; exhibit 15-2, pp. 15-25). Not performing a DCF analysis of the oil pipeline group also seemed at odds with the staff's use of that very group while proposing a hypothetical capital structure for EPC (*see* exhibit 15-1, pp. 7-8; exhibit 15-2, p. 7).

Despite the possible shortcomings in the staff's presentation, it is more reasonable to try to work with the staff's proposed range of rates of return, 12.82%-15.6%, than the proposals of EPC or Alaska. There are enough indications to support the staff's conclusion that EPC's financial and business risks are not as great as the staff's selected group of comparable natural gas pipelines (exhibit 15-1, pp. 10-13). But neither is EPC quite as risk-free as the staff suggests.

EPC is a feeder-pipeline to TAPS. Therefore, any serious operating problems at TAPS could have a ripple-effect upon EPC and cause a change to its own operations, possibly even a shutdown. In addition, as an offshore pipeline, EPC already is facing heightened environmental concerns as evidenced by its monitoring costs and the possibility that it may have to incur additional costs to mitigate potential damages resulting from the pipeline's operations.

In these circumstances, it is concluded that a reasonable rate of return on EPC's common equity is 13.7%, a number somewhat below the average rate for the staff's group of natural gas pipelines. This number, as discussed, is not mathematically precise, but it has a relatively rational foundation and is to be used by EPC.

There is simply no adequate basis to use the rate of return proposals of EPC or Alaska. As for EPC, it has never justified using its respective parents' stocks to perform its DCF analysis, neither proving nor even asserting that the diversified parents' business operations and risks are in any way similar to those of EPC. Nor has EPC ever proved its assertion, as noted, that its business risks are greater than those of its parents and, thus, it allegedly has been conservative to choose its parents as a proxy.

Moreover, the company's DCF analysis — handpicking a single day or so-called spot yield, rather than using six months, of data — fails to adhere to the approach which the Commission wants to be used in arriving at a dividend yield, as mentioned above (exhibit 9-0, p. 11; exhibit 9-3). In addition, EPC's own analysis revealed a rate of return of only 12.01% (*Compare* exhibits 9-3 and 9-3.2 *with* exhibit 15-2, p. 36). Yet, rather than sticking with that number, EPC increased it to 15.51% (*id.*) by adding on a so-called market-to-book ratio which the Commission has not endorsed for this purpose. Such a substantial adjustment also has the effect of improperly converting a market-oriented analysis like a DCF into a book-oriented evaluation.

Having generated such an inflated number, EPC is not helped here by three other analyses which it performed, purporting to show that a rate of 15.5% is reasonable. One of these analyses, a so-called CAPM study (a type of risk premium analysis), is too heavily weighted with historical data reaching back over 60 years (exhibit 9-0, pp. 17-19; exhibit 9-3.3). In no way has such data been shown to be representative of current economic conditions, which current conditions are critical in trying to determine the present cost of EPC's common equity.

The second analysis, a so-called comparable earnings study, is based upon the average return earned on book equity by EPC's parents over a ten-year period, compared with the average return on net worth earned or to be earned by the companies making up the Dow Jones Industrials (exhibit 9-0, pp. 15-17; exhibit 9-4.2). EPC has made no effort to show why it should be considered akin to its parents, given their diversified operations and risks, let alone the Dow Jones Industrials, or why the numbers produced for these groups are relevant here. The third analysis, a so-called internal rate of return study, also rests upon EPC's parents (exhibit 9-0, pp. 19-21; exhibit 9-3.4). Not only is this study questionable in view of the parents' role, it has no adequate support particularly for its assumption as to the substantial jump in the price of stock.

Nor is EPC aided here by yet another study which it performed. According to this study, a so-called risk positioning approach, EPC's proposed rate of return on common equity could be increased by another two percentage points (exhibit 10-0, p. 5).

This study suffers from the same basic defect contained in EPC's CAPM study — an undue reliance upon historical data covering a number of decades, without adequate explanation of how that data relates to current economic conditions (*id.* at pp. 7-10). In addition, the study produces a risk premium by using short-term rather than long-term U.S. Treasury obligations (*id.* at pp. 8-10). This approach not only inflates the premium unreasonably, it runs counter to the Commission's policy of using long-term federal obligations to determine such a premium. *See, e.g., Midwestern, supra*, 31 FERC at pp. 61,722-23.

As for Alaska, its proposed nominal rate on common equity for EPC, 11.8%, is too low and riddled with flaws. The proposal, therefore, cannot be accepted or used in any way.

To begin, as noted, Alaska reached the illogical result that the estimated cost for EPC's long-term debt somehow exceeds the estimated cost for the company's common equity (*Compare* exhibit 14-0, p. 105, *with* exhibit 14-37, p. 3). That defect (Tr., *e.g.*, 1841-43) casts substantial doubt upon Alaska's entire position concerning the cost of EPC's equity. Additionally, Alaska has not even attempted to perform a DCF analysis for EPC or a proxy, despite the fact that the Commission favors the use of such an analysis.

What Alaska has done is to perform some type of risk premium analysis. But the analysis, which does not use enough current data to allow a forward-looking projection to be made (exhibit 14-0, p. 95), unreasonably concludes that EPC is virtually risk-free and, thus, entitled to a very low rate of return on equity (*id.* at pp. 87-92). The analysis relies too heavily upon a single oil pipeline, Buckeye Pipeline Company, L.P., which does not even operate in Alaska and may well be unique and not representative of a company like EPC for other reasons. Not the least of these reasons is the fact that Buckeye is a limited partnership that does not issue common stock (53 FERC ¶ 61,473, at p. 62,659 (1990)). Moreover, as in the case of the staff, Alaska does not give enough weight to the potential environmental and operating risks which EPC faces as an offshore pipeline feeding into TAPS.

3. Other Costs and Throughput

(a) As mentioned earlier, the staff takes issue on a number of grounds with EPC's treatment of DR&R — i.e., the future costs expected to be incurred relating to the dismantlement and removal of the Endicott facilities and the restoration of affected areas when production from the Endicott field terminates. One of these grounds was decided above, approving EPC's use of a UOT rather than a straight-line procedure which the staff favors. As to the remaining grounds, Alaska jumps into the fray only with regard to one of them — an earnings question — to be dealt with after addressing the other questions.

The first concerns the staff's contention that these future costs are too speculative or contingent and, thus, should not be reflected at all in EPC's rate at the present time (Initial brief, pp. 48-51). This ground is not a sufficient basis to deny EPC the opportunity to recover these costs currently.

Pursuant to relevant documents known as general permits, facility leases, and oil and gas leases administered by such government authorities as the U.S. Army Corps of Engineers and the state of Alaska, EPC has a DR&R obligation which it will have to fulfill unless these authorities decide largely for environmental reasons that it is not in their own best interests for EPC to do so (*see* exhibits 2-15 and 20-2). That EPC's present obligation to do the work possibly may be erased eventually, in whole or in part, is hardly an adequate reason to prevent the company from accumulating the necessary funds throughout the pipeline's life so that it will be ready and able to carry out its duty if the authorities do not absolve it of such a duty.

Not only is EPC correct in planning at this stage to do the work, it is far more reasonable for each barrel of oil moving through the pipeline to bear its fair share of these future costs than to impose a moratorium until government authorities have announced with certainty EPC's precise obligation. To wait until then before charging for DR&R could impose an enormous cost-burden all at once in a disproportionate manner, considering the dwindling volumes of oil produced and transported in the later years of the Endicott project, and thus could deter maximizing production of the remaining volumes in the reservoir.

Though no one can say now with certainty that EPC will in fact ultimately incur DR&R costs, in whole or in part, that is not the proper question or standard to determine whether such costs can be recovered in the company's rate at this juncture. The appropriate question is whether there is a reasonable probability EPC will have to incur such costs in the future. That question can be answered affirmatively because right now EPC must perform DR&R eventually, unless government authorities subsequently change their minds.

As the presiding judge observed in another Initial Decision (49 FERC ¶ 63,020, at p. 65,086),

> [i]n an administrative proceeding such as this, it is quite common for a regulatory agency like the FERC to have to make reasonable judgments or forecasts based upon the information available. That a judgment is couched in probabilities or approximations does not make it suspect or unreasonable, for in virtually every such proceeding there is bound to be some uncertainty. *See, e.g., Dayton Power & Light Co. v. Public Utilities Comm'n of Ohio*, 292 U.S. 290, 310 (1934)(Cardozo, J.); *FPC v. Transcontinental Gas Pipe Line Corp.*, 365 U.S. 1, 29 (1961).

The staff's wait-and-see, all-or-nothing approach to DR&R is unreasonable and cannot be adopted. The better procedure is to allow EPC to charge for the costs now, while imposing a condition which will require the company to refund moneys collected for the costs if federal or state authorities ultimately decide to absolve the company of its obligation in whole or in part. Even apart from actions taken by federal or state authorities, if for whatever reason the DR&R costs eventually turn out to be less than the amounts collected through EPC's rate, the company is to refund the difference. Such refund conditions are hereby imposed.

As a second ground, the staff also quarrels with the fact that EPC commingles DR&R revenues with the rest of the revenues received through its rate. According to the staff, it would be better to place the DR&R revenues in an escrow account, a so-called external fund, which would deny EPC the right which it presently has to incorporate the revenues into its normal cash flow and thereby make whatever use it chooses of them (Tr., *e.g.*, 208-09; 221-22; 728-29).

In the circumstances of this case, there is no need to establish an escrow account. DR&R costs involve both the production and transportation functions of the Endicott project. The production function will be responsible for the lion's share of these costs.

EPC's parents are responsible ultimately for all of these costs. Because the parents are not required throughout the project's life to set aside specific funds for DR&R purposes relating to the larger production aspect, it makes little sense to compel them to do so for the smaller pipeline part.

The staff goes on to argue that if EPC is allowed to commingle the DR&R revenues, it should be required to reduce its rate base by the amounts collected. EPC objects to this proposal, contending that its earnings will be reduced which will act as a disincentive to operate the pipeline as throughput drops off.

EPC wants to have its cake and eat it too. The company is receiving in advance substantial payments for DR&R which it is free to invest or use as it chooses. Just as in the case of other types of prepayments collected by regulated entities—such as ADIT, negative salvage for offshore gas pipeline operations, and decommissioning for nuclear power plants — the company should be obliged to reduce its rate base by the amounts received to recognize the fact that it has interest-free use of such moneys. EPC is to reduce its rate base by the amounts collected for DR&R.

As a third ground, the staff objects to EPC's factoring an inflation component into the DR&R costs. The staff considers inflation to be only one of a number of factors which could influence these costs and therefore argues that it is unfair and illogical to isolate and estimate inflation (Initial brief, p. 55).

It is the staff, however, which is being unfair and illogical on this point. Inflation is an economic fact of life which has been recurring annually since at least 1970 (Tr. 2081-82; exhibit 16-9 and exhibit 20-5). The only real question has been what is its annual rate. Alaska agrees with EPC that for purposes of DR&R, the rate is to be 4% per annum (exhibit 4-6, pp. 23-26; exhibit 12-0, p. 6). There is sufficient reason for the Commission to adopt this rate here.

In essence, the staff is collaterally attacking the Commission which has been incorporating an inflation factor into another type of future cost, decommissioning for nuclear power plants. The staff has given no reason for its proposed disparate treatment.

There is also an illogical aspect to the staff's argument about inflation. All participants in this case — the staff included — have agreed that EPC's estimated costs for DR&R are $15 million if 1987 were used as the base year or period (exhibit 1-10, p. 1). This means that all participants know full well that in the year when the Endicott project finally terminates, $15 million will be inadequate to pay for EPC's share of the DR&R costs. Unless an inflation factor is added, EPC will not be made whole for these future costs.

There is one final point concerning the staff's argument about inflation. The staff, as mentioned, considers inflation to be only one of a number of factors which could affect DR&R costs. It lists what it regards to be these other significant factors (exhibit 20-1, pp. 10-11). But they are not in any way similar to inflation, and are akin to comparing apples with oranges.

Inflation is a fact which can not only be predicted with some certainty, it can also be quantified or measured. On the other hand, the so-called other factors which the staff lists such as improvements in technology or changing tax law and investment environment — cannot be predicted with any degree of certainty, and are little more than abstract possibilities.

As a fourth and final ground, the staff challenges as too low the projected earnings which EPC assumes will be generated by the DR&R funds. Alaska joins in this dispute, also attacking EPC's assumption.

EPC's assumption is unreasonable. There is a need to adjust the projected DR&R earnings upward, thereby reducing the DR&R charge which EPC has to collect through its rate.

EPC has been unduly conservative assuming that the DR&R revenues it collects will only earn the average yield of U.S. Treasury notes with a two-year to four-year maturity. (exhibit 10-0, pp. 10 and 30-31; exhibit 10-1; exhibit 10-30, pp.56-58). Notwithstanding EPC's assertions, there is no rational basis to assume EPC will invest DR&R revenues in such risk-free securities which carry such a low yield.

EPC frankly admits that it incorporates DR&R revenues into its normal cash flow and is thereby free to make whatever use it chooses of the revenues. What is clear, as EPC acknowledges, is that the cash is not invested in the very types of debt obligations which EPC's unsupported assumption rests upon, risk-free short-term U.S. Treasury notes (Tr. 208-09; 221-22; 728-29).

Nor is EPC helped here by its theories as to why the DR&R earnings should be assumed to be so low. While EPC asserts that it runs the risk of not collecting DR&R revenues, due to such events as unanticipated throughput disruptions or discontinuance of operations resulting from low oil prices (exhibit 11-0, pp. 28-32; exhibit 11-16, pp. 36-38; Reply brief, pp. 38-39), the company already is being compensated for this risk by the increased rate of return on common equity which this decision is granting to it. There is no sound reason to double-count this risk.

As for EPC's theory that it also runs the risk of not collecting over time enough revenues to take care of its DR&R obligation (*id.*), that rationalization simply does not wash. If EPC ever discerns that its DR&R costs will be greater than the projections reflected in its initial rate, the company is always free to come to the Commission and request a rate increase for these costs.

Though Alaska agrees that EPC's assumed DR&R earnings rate is too low, it proposes an unwieldy alternative to handle the matter. The alternative would be to adopt some type of investment portfolio, for a specific period of time, whose earnings would equal that of a pension fund. Alaska proposes an earnings rate of 11.1% (exhibit 14-0, pp. 113-16).

Alaska's proposal has too much of a theoretical tone, even intimating that a proper procedure would be to establish an escrow account. Not only has an escrow-account proposal already been rejected here, Alaska's theory seems to recommend a specific investment portfolio at a particular, quite limited point in time which EPC's management would have to follow. Alaska has failed to show either why EPC's management has to adhere to a set investment formula or why an investment portfolio at a limited point in time would be relevant to calculate projected DR&R earnings for many years (*Cf.* Tr. 1575-87).

The more reasonable solution is to assume that the earnings rate on the DR&R revenues will be equal to the overall weighted average rate of return on EPC's debt and equity capital. That rate is 12.3% where, as found above, the long-term debt ratio is 43.5% and its cost is 10.5%, while the common equity ratio is 56.5% and its cost is 13.7%.

Even though the discussion until now has focused upon EPC's freedom to make whatever use it chooses of the DR&R revenues, the fact is that it is EPC's parents which really call the shots as to where the revenues should go, including into the parents' pockets (Tr. 221; 728-29). Certainly the parents are not investing the revenues in risk-free, low-earnings U.S. Treasury obligations.

There is strong reason to believe that EPC's parents will be able to earn at least the same amount on the DR&R revenues as they are able to earn on all of the capital invested in EPC itself (*Cf., e.g.*, exhibit 9-4.2). This is especially true given the fact that their investment in EPC appears to be less risky than other ventures, including the staff's group of comparable natural gas pipelines. Accordingly, without trying to prescribe an investment portfolio for EPC or its parents, it is hereby concluded that the earnings rate on the DR&R revenues is 12.3%.

(b) Legal and regulatory expenses are part of the operating and maintenance costs to be reflected in a regulated entity's rate. EPC has chosen to treat its legal and regulatory expenses in a different manner from all of its other costs to calculate its proposed initial rate.

With regard to all of the other costs, EPC has used the actual figures for calendar year 1988. But as to its legal and regulatory expenses, EPC has added its actual figures for 1987 beginning in October when the pipeline went into service, together with the actual figures for calendar year 1988 as well as the projections for these expenses for 1989. Then, the company has taken the time period covering these cumulative expenses, 2.25 years, and divided that into the cumulative expenses, thereby spreading or amortizing the costs, resulting in an annual figure of $1.07 million (exhibit 4-6, pp. 32-33; exhibit 4-5.11).

The staff does not object to EPC's using the actual figures for these expenses for 1987 and 1988 in order to determine whether the company must make refunds for these periods. But for 1989 and thereafter, the staff argues that EPC must use the actual figures for 1988 alone, which the staff would then spread or amortize over 5 years, resulting in an annual figure of $151,200 (exhibit 16-1, pp. 10-11). Alaska essentially agrees with the staff, but would amortize the actual 1988 expenses over 3 years, resulting in an annual figure of $252,000 (exhibit 13-0, p. 56).

This issue would be a good candidate to be handled by a monthly variable, cost-tracking tariff, especially given the uncertainties of what these expenses are likely to be. The point is underscored by the fact that there is no way to predict when, if ever, EPC may incur these costs in the future, such as by coming back to the Commission to propose a rate change. However, because of the Commission's recent *Kuparuk* decision, *supra*, no such variable tariff will be imposed.

In these circumstances, it is concluded that for purposes of calculating a fixed initial rate EPC can lump together its actual legal and regulatory costs for 1987 and 1988 with its projected costs for 1989. However, there is no rational basis to amortize this figure over only 2.25 years, as EPC proposes — thereby falsely intimating that the annual costs will be $1.07 million indefinitely. Nor is it any more rational to amortize the costs over only 3 or 5 years, as Alaska and the staff respectively suggest — albeit while using lower costs.

There is good reason to believe that the company will have little or no incentive to come to the Commission to propose a rate change and thereby incur additional legal and regulatory expenses in the future. This is because if a fixed rate is set for EPC despite the fact that its rate base will be declining, its return allowance will be overstated repeatedly. Consequently, EPC is to amortize its cumulative 1987-1989 actual and projected expenses over the entire life of the Endicott project, estimated at the time of the hearings to end in the year 2006 (exhibit 4-4; exhibit 1-9, pp. 5-6).

(c) Throughput (the volume of oil moving through the pipeline) is an essential element in determining a per-unit price or rate. It is used as the denominator to be divided into a regulated entity's total cost of service, the numerator.

If a fixed rate rather than a variable rate were set for EPC, as appears likely because of *Kuparuk*, there is a question as to whether the throughput should be the actual average daily amount for calendar year 1988, as EPC and Alaska propose, or a projected higher number, as the staff proposes. The staff's proposal cannot be accepted.

The staff asserts that it is theoretically possible to produce greater volumes of oil from the Endicott reservoir and thus have greater volumes move through the pipeline (exhibit 18-1, pp. 10-11). But the staff acknowledges that it did not perform its own engineering analysis to determine such matters as field conditions, a production profile for the field, or whether its proposed higher production rate would damage the Endicott reservoir (Tr., *e.g.*, 2024; 2035). In these circumstances, there is no reasonable basis to adopt the staff's estimate.

The better approach in any event would be to use the actual throughput for 1988. Given the fact that, with the exception of legal and regulatory expenses, EPC's actual 1988 costs would be used as the numerator (assuming no adoption of a variable rate), the actual 1988 throughput as the denominator would be the preferable match.