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ON THE ASSESSMENT OF RISK

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INTRODUCTION

THE CONCEPT OF RISK has so permeated the financial community that no one needs to be convinced of the necessity of including risk in investment analysis. Still of controversy is what constitutes risk and how it should be measured. This paper examines the statistical properties of one measure of risk which has had wide acceptance in the academic community: namely the coefficient of non-diversifiable risk or more simply the beta coefficient in the market model.

The next section defines this beta coefficient and presents a brief non-rigorous justification of its use as a measure of risk. After discussing the sample and its basic properties in Section III, Section IV examines the stationarity of this beta coefficient over time and proposes a method of obtaining improved assessments of this measure of risk.

II. THE RATIONALE OF BETA AS A MEASURE OF RISK

The interpretation of the beta coefficient as a measure of risk rests upon the empirical validity of the market model. This model asserts that the return from time (t-1) to t on asset i, $\tilde{R}_{it}$,[1] is a linear function of a market factor common to all assets $\tilde{M}_t$, and independent factors unique to asset i, $\tilde{\varepsilon}_{it}$.

Symbolically, this relationship takes the form

$$\tilde{R}_{it} = \alpha_i + \beta_i \tilde{M}_t + \tilde{\varepsilon}_{it}, \tag{1}$$

where the tilde indicates a random variable, α_i is a parameter whose value is such that the expected value of $\tilde{\varepsilon}_{it}$ is zero, and β_i is a parameter appropriate to asset i.[2] That the random variables $\tilde{\varepsilon}_{it}$ are assumed to be independent and

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1. In this paper, return will be measured as the ratio of the value of the investment at time t with dividends reinvested to the value of the investment at time (t-1). Dividends are assumed reinvested at time t.

2. The parameter β_i is defined as Cov $(\tilde{R}_i, \tilde{M})$/Var $(\tilde{M})$.

unique to asset i implies that Cov ($\tilde{\varepsilon}_{it}$, $\tilde{M}_t$) is zero and that Cov ($\tilde{\varepsilon}_{it}$, $\tilde{\varepsilon}_{jt}$), $i \neq j$, are zero. This last conclusion is tantamount to assuming the absence of industry effects.

The empirical validity of the market model as it applies to common stocks listed on the NYSE has been examined extensively in the literature.[3] The principal conclusions are: (1) The linearity assumption of the model is adequate.[4] (2) The variables $\tilde{\varepsilon}_{it}$ cannot be assumed independent between securities because of the existence of industry effects. However, these industry effects, as documented by King,[5] probably account for only about ten percent of the variation in returns, so that as a first approximation they can be ignored. (3) The unique factors $\tilde{\varepsilon}_{it}$ correspond more closely to non-normal stable variates than to normal ones. This conclusion means that variances and covariances of the unique factors do not exist. Nonetheless, this paper will make the more common assumption of the existence of these statistics in justifying the beta coefficient as a measure of risk since Fama[6] and Jensen[7] have shown that this coefficient can still be interpreted as a measure of risk under the assumption that the $\tilde{\varepsilon}_{it}$'s are non-normal stable variates.

That the beta coefficient, β_i, in the market model can be interpreted as a measure of risk will be justified in two different ways: the portfolio approach and the equilibrium approach.

A. *The Portfolio Approach*

The important assumption underlying the portfolio approach is that individuals evaluate the risk of a portfolio as a whole rather than the risk of each asset individually. An example will illustrate the meaning of this statement. Consider two assets, each of which by itself is extremely risky. If, however, it is always the case that when one of the assets has a high return, the other has a low return, the return on a combination of these two assets in a portfolio may be constant. Thus, the return on the portfolio may be risk free whereas each of the assets has a highly uncertain return. The discussion of such an

3. See Marshall E. Blume, "Portfolio Theory: A Step Towards Its Practical Application," forthcoming *Journal of Business;* Eugene F. Fama, "The Behavior of Stock Market Prices," *Journal of Business* (1965), 34-105; Eugene F. Fama, Lawrence Fisher, Michael Jensen, and Richard Roll, "The Adjustment of Stock Prices to New Information," *International Economic Review* (1969), 1-21; Michael Jensen, "Risk, the Pricing of Capital Assets, and the Evaluation of Investment Portfolios," *Journal of Business* (1969), 167-247; Benjamin F. King, "Market and Industry Factors in Stock Price Behavior," *Journal of Business* (1966), 139-90; and William F. Sharpe, "Mutual Fund Performance," *Journal of Business* (1966), 119-38.

4. The linearity assumption of the model should not be confused with the equilibrium requirement of William F. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk," *Journal of Finance* (1964), 425-42, which states that $\alpha_i = (1 - \beta_i) R_F$, where R_F is the risk free rate. It is quite possible that this equality does not hold and at the same time that the market model is linear.

5. King, *op. cit.*

6. Eugene F. Fama, "Risk, Return, and Equilibrium" (Report No. 6831, University of Chicago, Center for Mathematical Studies in Business and Economics, June, 1968).

7. Jensen, *op. cit.*

obvious point may seem unwarranted, but there is very little empirical work which indicates that people do in fact behave according to it.

Now if an individual is willing to judge the risk inherent in a portfolio solely in terms of the variance of the future aggregate returns, the risk of a portfolio of n securities with an equal amount invested in each, according to the market model, will be given by

$$\mathrm{Var}\,(\tilde{W}_t) = \left(\sum_{i=1}^{n} \frac{1}{n}\beta_i\right)^2 \mathrm{Var}\,(\tilde{M}_t) + \sum_{i=1}^{n} \left(\frac{1}{n}\right)^2 \mathrm{Var}\,(\tilde{\varepsilon}_{it}) \qquad (2)$$

where $\tilde{W}_t$ is the return on the portfolio. Equation (2) can be rewritten as

$$\mathrm{Var}\,(\tilde{W}_t) = \bar{\beta}^2\,\mathrm{Var}\,(\tilde{M}_t) + \frac{\overline{\mathrm{Var}\,(\tilde{\varepsilon})}}{n} \qquad (3)$$

where the bar indicates an average. As one diversifies by increasing the number of securities n, the last term in equation (3) will decrease. Evans and Archer[8] have shown empirically that this process of diversification proceeds quite rapidly, and with ten or more securities most of the effect of diversification has taken place. For a well diversified portfolio, Var $(\tilde{W}_t)$ will approximate $\bar{\beta}^2$ Var $(\tilde{M}_t)$. Since Var $(\tilde{M}_t)$ is the same for all securities, $\bar{\beta}$ becomes a measure of risk for a portfolio and thus β_i, as it contributes to the value of $\bar{\beta}$, is a measure of risk for a security. The larger the value of β_i, the more risk the security will contribute to a portfolio.[9]

B. *The Equilibrium Approach*

Using the market model, Sharpe[10] and Lintner,[11] as clarified by Fama,[12] have developed a theory of equilibrium in the capital markets. This theory relates the risk premium for an individual security, $E(\tilde{R}_{it}) - R_F$, where R_F is the risk free rate, to the risk premium of the market, $E(\tilde{M}_t) - R_F$, by the formula

$$E(\tilde{R}_{it}) - R_F = \beta_i[E(\tilde{M}_t) - R_F]. \qquad (4)$$

The risk premium for an individual security is proportional to the risk premium for the market. The constant of proportionality β_i can therefore be interpreted as a measure of risk for individual securities.

8. John L. Evans and Stephan H. Archer, "Diversification and the Reduction of Dispersion: An Empirical Analysis," *Journal of Finance* (1968), 761-68.

9. This argument has been extended to a non-Gaussian, symmetric stable world by E. F. Fama, "Portfolio Analysis in a Stable Paretian Market," *Management Science* (1965), 404-19; and P. A. Samuelson, "Efficient Portfolio Selection for Pareto-Levy Investments," *Journal of Financial and Quantitative Analysis* (1967), 107-22.

10. Sharpe, "Capital Asset Prices," *op. cit.*

11. John Lintner, "The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets," *Review of Economics and Statistics* (1965), 13-37.

12. Eugene F. Fama, "Risk, Return, and Equilibrium: Some Clarifying Comments," *Journal of Finance* (1968), 29-40.

This theory of equilibrium, although theoretically sound, is based upon numerous assumptions which obviously do not hold in the real world. A theoretical model, however, should not be judged by the accuracy of its assumptions but rather by the accuracy of its predictions. The empirical work of Friend and Blume[13] suggests that the predictions of this model are seriously biased and that this bias is primarily attributable to the inaccuracy of one key assumption, namely that the borrowing and lending rates are equal and the same for all investors. Therefore, although Sharpe's and Lintner's theory of equilibrium can be used as a justification for β_i as measure of risk, it is a weaker and considerably less robust justification than that provided by the portfolio approach.

III. The Sample and Its Properties

The sample was taken from the updated Price Relative File of the Center for Research in Security Prices at the Graduate School of Business, University of Chicago. This file contains the monthly investment relatives, adjusted for dividends and capital changes of all common stocks listed on the New York Stock Exchange during any part of the period from January 1926 through June 1968, for the months in which they were listed. Six equal time periods beginning in July 1926 and ending in June 1968 were examined. Table 1 lists these six periods and the number of companies in each for which there was a complete history of monthly return data. This number ranged from 415 to 890.

The investment relatives for a particular security and a particular period were regressed[14] upon the corresponding combination market link relatives, which were originally prepared by Fisher[15] as a measure of the market factor. This process was repeated for each security and each period, yielding, for instance, in the July 1926 through June 1933 period, 415 separate regressions. The average coefficient of determination of these 415 regressions was 0.51. The corresponding average coefficients of determination for the next five periods were, respectively, 0.49, 0.36, 0.32, 0.25, and 0.28. These figures are consistent with King's findings[16] in that the proportion of the variance of returns explained by the market declined steadily until 1960 when his sample terminated. Since 1960, the importance of the market factor has increased slightly according to these figures.

Table 1, besides giving the number of companies analyzed, summarizes the distributions of the estimated beta coefficients in terms of the means, standard deviations, and various fractiles of these distributions. In addition, the number of estimated betas which were less than zero is given. In three of the periods,

13. Irwin Friend and Marshall Blume, "Measurement of Portfolio Performance Under Uncertainty," *American Economic Review* (1970), 561-75.

14. John Wise, "Linear Estimators for Linear Regression Systems Having Infinite Variances," (Berkeley-Stanford Mathematics-Economics Seminar, October, 1963) has given some justification for the use of least squares in estimating coefficients of regressions in which the disturbances are non-normal symmetric stable variates.

15. Lawrence Fisher, "Some New Stock-Market Indexes," *Journal of Business* (1966), 191-225.

16. King, *op. cit.*

TABLE 1
DESCRIPTIVE SUMMARY OF ESTIMATED BETA COEFFICIENTS

Period	Number of Companies	Mean	Standard Deviation	Number of BETAS less than Zero	Fractiles .10	.25	.50	.75	.90
7/26-6/33	415	1.051	0.462	1	0.498	0.711	1.023	1.352	1.616
7/33-6/40	604	1.036	0.474	0	0.436	0.701	1.015	1.349	1.581
7/40-6/47	731	0.990	0.504	0	0.500	0.643	0.872	1.186	1.606
7/47-6/54	870	1.010	0.409	2	0.473	0.727	0.996	1.263	1.565
7/54-6/61	890	0.998	0.423	0	0.458	0.678	0.984	1.250	1.558
7/61-6/68	847	0.962	0.390	4	0.475	0.681	0.934	1.199	1.491

none of the estimated betas was negative. Of the 4357 betas estimated in all six periods, only seven or 0.16 per cent were negative. This means that although the inclusion of a stock which moves counter to the market can reduce the risk of a portfolio substantially, there are virtually no opportunities to do this. Nearly every stock appears to move with the market.[17]

IV. The Stationarity of Beta over Time

No economic variable including the beta coefficient is constant over time. Yet for some purposes, an individual might be willing to act *as if* the values of beta for individual securities were constant or stationary over time. For example, a person who wishes to assess the future risk of a well diversified portfolio is really interested in the behavior of averages of the β_i's over time and not directly in the values for individual securities. For the purposes of evaluating a portfolio, it may be sufficient that the historical values of β_i be unbiased estimates of the future values for an individual to act *as if* the values of the β_i's for individual securities are stationary over time. This is because the errors in the assessment of an average will tend to be less than those of the components of the average providing that the errors in the assessments of the components are independent of each other.[18] Yet, a statistician or a person who wishes to assess the risk of an individual security may have completely different standards in determining whether he would act as if the β_i's are constant over time. The remainder of the paper examines the stationarity of the β_i's from the point of view of a person who wishes to analyze a portfolio.

A. *Correlations*

To examine the empirical behavior of the risk measures for portfolios over time, arbitrary portfolios of n securities were selected as follows: The estimates of β_i were derived using data from the first period, July 1926 through June 1933, and were then ranked in ascending order.[19] The first portfolio of n securities consisted of those securities with the n smallest estimates of β_i. The second portfolio consisted of those securities with the next n smallest estimates of β_i, and so on until the number of securities remaining was less than n. The number of securities n was allowed to vary over 1, 2, 4, 7, 10, 20, 35, 50, 75, and 100. This process was repeated for each of the next four periods.

Table 2 presents the product moment and rank order correlation coefficients between the risk measures for portfolios of n securities assuming an equal investment in each security estimated in one period and the corresponding risk

17. The use of considerably less than seven years of monthly data such as two or three years to estimate the beta coefficient results in a larger proportion of negative estimates. This larger proportion is probably due to sampling errors which, as documented in Richard Roll, "The Efficient Market Model Applied to U. S. Treasury Bill Rates," (Unpublished Ph.D. thesis, Graduate School of Business, University of Chicago, 1968) may be quite large for models with non-normal symmetric stable disturbances.

18. This property of averages does not hold for all distributions (*cf.* Eugene F. Fama, "Portfolio Analysis in a Stable Paretian Market"), but for the distributions associated with stock market returns it almost certainly holds.

19. Only securities which also had complete data in the next seven year period were included in this ranking.

measure for the same portfolio estimated in the next period.[20] The risk measure calculated using the earlier data might be regarded as an individual's assessment of the future risk, and the measure calculated using the later data can be regarded as the realized risk. Thus, these correlation coefficients can be interpreted as a measure of the accuracy of one's assessments, which in this case are simple extrapolations of historical data.

TABLE 2
PRODUCT MOMENT AND RANK ORDER CORRELATION COEFFICIENTS OF BETAS FOR PORTFOLIOS OF N SECURITIES

Number of Securities per Portfolio	7/26-6/33 and 7/33-6/40		7/33-6/40 and 7/40-6/47		7/40-6/47 and 7/47-6/54		7/47-6/54 and 7/54-6/61		7/54-6/61 and 7/61-6/68	
	P.M.	Rank	P.M.	Rank	P.M.	Rank	P.M.	Rank	P.M.	Rank
1	0.63	0.69	0.62	0.73	0.59	0.65	0.65	0.67	0.60	0.62
2	0.71	0.75	0.76	0.83	0.72	0.79	0.76	0.76	0.73	0.74
4	0.80	0.84	0.85	0.90	0.81	0.89	0.84	0.84	0.84	0.85
7	0.86	0.90	0.91	0.93	0.88	0.93	0.87	0.88	0.88	0.89
10	0.89	0.93	0.94	0.95	0.90	0.95	0.92	0.93	0.92	0.93
20	0.93	0.99	0.97	0.98	0.95	0.98	0.95	0.96	0.97	0.98
35	0.96	1.00	0.98	0.99	0.95	0.99	0.97	0.98	0.97	0.97
50	0.98	1.00	0.99	0.98	0.98	0.99	0.98	0.98	0.98	0.97

The values of these correlation coefficients are striking. For the assessments based upon the data from July 1926 through June 1933 and evaluated using data from July 1933 through June 1940, the product moment correlations varied from 0.63 for single securities to 0.98 for portfolios of 50 securities. The high value of the latter coefficient indicates that substantially all of the variation in the risk among portfolios of 50 securities can be explained by assessments based upon previous data. The former correlation suggests that assessments for individual securities derived from historical data can explain roughly 36 per cent of the variation in the future estimated values, leaving about 64 per cent unexplained.[21]

These results, which are typical of the other periods, suggest that at least as measured by the correlation coefficients, naively extrapolated assessments of future risk for larger portfolios are remarkably accurate, whereas extrapolated assessments of future risk for individual securities and smaller portfolios are of some, but limited value in forecasting the future.

B. *A Closer Examination*

Table 3 presents the actual estimates of the risk parameters for portfolios of 100 securities for successive periods. For all five different sets of portfolios, the rank order correlations between the successive estimates are one, but there is obviously some tendency for the estimated values of the risk parameter to

20. Because of the small number of portfolios of 100 securities, correlations are not presented in Table 2 for these portfolios.

21. This large magnitude of unexplained variation may make the beta coefficient an inadequate measure of risk for analyzing the cost of equity for an individual firm although it may be adequate for cross-section analyses of cost of equity.

TABLE 3
ESTIMATED BETA COEFFICIENTS FOR PORTFOLIOS OF 100 SECURITIES IN TWO SUCCESSIVE PERIODS

Portfolio	7/26-6/33	7/33-6/40	7/33-6/40	7/40-6/47	7/40-6/47	7/47-6/54	7/47-6/54	7/54-6/61	7/54-6/61	7/61-6/68
1	0.528	0.610	0.394	0.573	0.442	0.593	0.385	0.553	0.393	0.620
2	0.898	1.004	0.708	0.784	0.615	0.776	0.654	0.748	0.612	0.707
3	1.225	1.296	0.925	0.902	0.746	0.887	0.832	0.971	0.810	0.861
4			1.177	1.145	0.876	1.008	0.967	1.010	0.987	0.914
5			1.403	1.354	1.037	1.124	1.093	1.095	1.138	0.995
6					1.282	1.251	1.245	1.243	1.337	1.169

change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the future values, and furthermore the values of the risk coefficients as measured by the estimates of β_1 tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios.

C. *A Method of Correction*

In so far as the rate of regression towards the mean is stationary over time, one can in principle correct for this tendency in forming one's assessments. An obvious method is to regress the estimated values of β_1 in one period on the values estimated in a previous period and to use this estimated relationship to modify one's assessments of the future.

Table 4 presents these regressions for five successive periods of time for individual securities.[22] The slope coefficients are all less than one in agreement with the regression tendency, observed above. The coefficients themselves do change over time, so that the use of the historical rate of regression to correct

TABLE 4
MEASUREMENT OF REGRESSION TENDENCY OF ESTIMATED BETA COEFFICIENTS FOR INDIVIDUAL SECURITIES

Regression Tendency Implied Between Periods	$\beta_2 = a + b\beta_1$
7/33-6/40 and 7/26-6/33	$\beta_2 = 0.320 + 0.714\beta_1$
7/40-6/47 and 7/33-6/40	$\beta_2 = 0.265 + 0.750\beta_1$
7/47-6/54 and 7/40-6/47	$\beta_2 = 0.526 + 0.489\beta_1$
7/54-6/61 and 7/47-6/54	$\beta_2 = 0.343 + 0.677\beta_1$
7/61-6/68 and 7/54-6/61	$\beta_2 = 0.399 + 0.546\beta_1$

22. The reader should not think of these regressions as a test of the stationarity of the risk of securities over time but rather merely as a test of the accuracy of the assessments of future risk which happen to be derived as historical estimates. In this test of accuracy, the independent variable in these regressions is measured without error, so that the estimated coefficients are unbiased. In the test of the stationarity of the risk measures over time, the independent variable would be measured with error, so that the coefficients in Table 4 would be biased.

for the future rate will not perfectly adjust the assessments and may even overcorrect by introducing larger errors into the assessments than were present in the unadjusted data.

To examine the efficacy of using historical rates of regression to correct one's assessments, the estimated risk coefficients for the individual securities for the period from July 1933 through June 1940 were modified using the first equation in Table 4 to obtain adjusted risk coefficients under the assumption that the future rate of regression will be the same as the past. This process was repeated for each of the next three periods using respectively the next three equations in Table 4 to estimate the rate of regression.

Table 5 compares these adjusted assessments with the unadjusted assessments which were used in Tables 2 and 3. For the portfolios selected previously using the data from July 1933 through June 1940, both the unadjusted

TABLE 5
MEAN SQUARE ERRORS BETWEEN ASSESSMENTS AND FUTURE ESTIMATED VALUES

Number of Sec./ Port.	Assessments Based Upon 7/33-6/40 unadjusted	adjusted	7/40-6/47 unadjusted	adjusted	7/47-6/54 unadjusted	adjusted	7/54-6/61 unadjusted	adjusted
1	0.1929	0.1808	0.1747	0.1261	0.1203	0.1087	0.1305	0.1013
2	0.0915	0.0813	0.1218	0.0736	0.0729	0.0614	0.0827	0.0535
4	0.0538	0.0453	0.0958	0.0483	0.0495	0.0381	0.0587	0.0296
7	0.0323	0.0247	0.0631	0.0276	0.0387	0.0281	0.0523	0.0231
10	0.0243	0.0174	0.0535	0.0220	0.0305	0.0189	0.0430	0.0169
20	0.0160	0.0090	0.0328	0.0106	0.0258	0.0139	0.0291	0.0089
35	0.0120	0.0055	0.0266	0.0080	0.0197	0.0101	0.0302	0.0089
50	0.0096	0.0046	0.0192	0.0046	0.0122	0.0097	0.0237	0.0064
75	0.0081	0.0035	0.0269	0.0067	0.0112	0.0078	0.0193	0.0056
100	0.0084	0.0020	0.0157	0.0035	0.0114	0.0084	0.0195	0.0056

and adjusted assessments of future risk were obtained. The accuracy of these two alternative methods of assessment were compared through the mean squared errors of the assessments versus the estimated risk coefficients in the next period, July 1940 through June 1947.[23] This process was repeated for each of the next three periods.

For individual securities as well as portfolios of two or more securities, the assessments adjusted for the historical rate of regression are more accurate than the unadjusted or naive assessments. Thus, an improvement in the accuracy of one's assessments of risk can be obtained by adjusting for the historical rate of regression even though the rate of regression over time is not strictly stationary.

23. The mean square error was calculated by $\frac{\Sigma(\beta_1 - \beta_2)^2}{n}$ where β_1 is the assessed value of the future risk, β_2 is the estimated value of the risk, and n is the number of portfolios. In using an estimate of beta rather than the actual value, the mean square error will be biased upwards, but the effect of this bias will be the same for both the adjusted and unadjusted assessments.

V. Conclusion

This paper examined the empirical behavior of one measure of risk over time. There was some tendency for the estimated values of these risk measures to regress towards the mean over time. Correcting for this regression tendency resulted in considerably more accurate assessments of the future values of risk.

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COST OF EQUITY FOR ENERGY UTILITIES: BEYOND THE CAPM

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ABSTRACT

The Capital Asset Pricing Model (CAPM) is applied in regulatory cases to estimate the required rate of return, or cost of equity, for low-beta, value-style energy utilities, despite the model's well documented mispricing of investments with similar characteristics. This paper examines CAPM-based estimates for a sample of American and Canadian energy utilities to assess the risk premium error. We find that the CAPM significantly underestimates the risk premium for energy utilities compared to its historical value by an annualized average of more than 4%. Two CAPM extensions, the Fama-French model and an adjusted CAPM, provide econometric estimates of the risk premium that do not present a significant misevaluation.

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1. INTRODUCTION

An important aspect of the regulatory process for energy utilities is the determination of their equity rate of return. This return, also known as the cost of equity capital, represents the expected remuneration of the shareholders of the utilities. It is a crucial component of their total cost of capital, which is central to their investment policy and serves as a basis for setting up the rates to their customers. The purpose of this paper is to highlight the problems of the most commonly used model to determine the equity rate of return for energy utilities and to propose two alternative models that empirically improve on the estimation. By providing new direct and focused evidence for energy utilities, our analysis contributes to the knowledge of energy, regulatory and financial economists, as well as regulators, who are concerned with rate determination.

Regulatory bodies, like the National Energy Board in Canada or the Federal Energy Regulatory Commission in the United States, have the mandate to set the equity rate of return so that it is fair and reasonable. Specifically, according to Bonbright, Danielsen and Kamerschen (1988, Chap. 10), the return should provide the ability to attract and retain capital (the capital-attraction criterion), encourage efficient managerial practice (the management-efficiency criterion), promote consumer rationing (the consumer-rationing criterion), give a reasonably stable and predictable rate level to ratepayers (the rate-level stability and predictability criterion) and ensure fairness to investors (the fairness to investors criterion). While the first four criteria are designed primarily in the interest of the consuming public, the last criterion acts as an equally-important protection for private owners against confiscatory regulation. Its requirement involves determining the return available from the application of the capital to other enterprises of like risk, which demands an understanding of the risk-return relationship in the equity market.

Traditionally, the regulated return has been set through hearings, where arguments on the issue of fairness could be debated. But since the 1990s, numerous boards have adopted an annual mechanism known as a "rate of return formula" or a "rate adjustment formula". This mechanism determines automatically the allowed rate of return through a calculation that explicitly accounts for the risk-return relationship in the equity market. The use of rate adjustment formulas is particularly prevalent in Canada since the landmark March 1995 decision by the National Energy Board (Decision RH-2-94), which sets the stage for the widespread adoption of closely related formulas by provincial regulators.

Most rate adjustment formulas use a method known as the Equity Risk Premium method.[1] This method can be summarized as calculating a utility's equity rate of return as the risk-free rate of return plus a premium that reflects its risk. The risk-free rate is usually related to the yield on a long-term government bond. The risk premium is obtained from the Capital Asset Pricing Model (CAPM) of Sharpe (1964) and Lintner (1965), a classic model of capital market equilibrium. It is equal to the utility's beta, a measure of its systematic risk, multiplied by the market portfolio risk premium. The Equity Risk Premium method has a number of

[1] There exist other methods for estimating the rate of return, most notably the Comparable Earnings method and the Discounted Cash Flows method. See Morin (2006) for a description. These methods are generally not directly incorporated in the rate adjustment formulas.

advantages. First, it is supported by a solid theoretical foundation in the academic literature, thus providing a sound basis for understanding the risk-return relationship. Second, it can be estimated based on stock returns, thereby making it more objective than other methods, and relating it to current market conditions. Third, it is relatively simple to apply and requires data that can be obtained easily.

The Equity Risk Premium method is not, however, without shortcomings. Arguably its most criticized feature is the use of the CAPM as the basis to determine the risk premium. While the CAPM is one of the most important developments in finance, research over the last forty years has produced a large body of work critical of the model. On the theoretical side, Cochrane (1999) summarizes the current most prevalent academic view: "In retrospect, it is surprising that the CAPM worked so well for so long. The assumptions on which it is built are very stylized and simplified."[2] For example, at least since Merton (1973), it is recognized that factors, state variables or sources of priced risk beyond the movements in the market portfolio (the only risk factor in the CAPM) might be needed to explain why some risk premiums are higher than others. On the empirical side, the finance literature abounds with CAPM deficiencies (so-called "anomalies"). Fama and French (2004) review this literature to highlight that the CAPM is problematic in the estimation of the risk premium of low-beta firms, small-capitalisation firms and value (or low-growth) firms. While these problems have been well documented in the finance literature, their effects have not yet been fully explored for energy utilities, which may be part of the reasons why the CAPM is still widely used in rate adjustment formulas. In particular, as the CAPM does not empirically provide a valid risk-return relationship for the equity market, it might fall short of the requirement associated with the fairness to investors' criterion.

Considering the importance of the CAPM in determining the regulated equity rate of return, the objectives of this paper are two-folds. First, we re-examine the use of the model in the context of energy utilities to determine if it is problematic. As utilities are typically low-beta, value-oriented investments, the finance literature suggests that the model will have difficulties in estimating their risk premiums. We analyze the issue empirically by estimating the model and its resulting risk premiums for a sample of Canadian and American energy utilities mostly related to the gas distribution sector, and by testing for the presence of significant differences between the model's risk premium estimates and the historical ones.

Second, we implement two alternative models that are designed to circumvent some of the empirical problems of the CAPM. The first alternative is a three-factor model proposed by Fama and French (1993) (the Fama-French model hereafter). This model has been used to estimate the cost of equity by Fama and French (1997) for general industrial sectors and by Schink and Bower (1994) for the utilities sector in particular. The second alternative is a modified CAPM that includes the adjustments proposed by Blume (1975) and Litzenberger, Ramaswamy and Sosin (1980) (the Adjusted CAPM hereafter). The Fama-French model and the Adjusted CAPM provide useful comparisons with the CAPM on the estimation of the risk premiums of energy utilities.

Our empirical results can be summarized as follows. First, the CAPM significantly underestimates the risk premiums of energy utilities compared to their

[2] Cochrane (1999), p. 39.

historical values. The underestimations are economically important, with annualized averages of respectively 4.5% and 6.2% for the Canadian and American gas utilities we consider, and are consistent with the finance literature on the mispricing of low-beta, value-oriented stocks. Second, the Fama-French model and the Adjusted CAPM are both able to provide costs of equity that are not significantly different from the historical ones. Our results show that the value premium, in the case of the Fama-French model, and a bias correction, in the case of the Adjusted CAPM, are important in eliminating the CAPM underestimations. Both models suggest average risk premiums between 4% and 8% for gas utilities portfolios, and are relevant at the individual utility level as well as at the utilities sector level.

Overall, we conclude that the CAPM is problematic in estimating econometrically the cost of equity of energy utilities. The Fama-French model and the Adjusted CAPM are well specified for this purpose as they reduce considerably the estimation errors. These models could thus be considered as alternatives to the CAPM in the Equity Risk Premium method employed by regulatory bodies to obtain the risk-return relationship for the fairness to investors' criterion.

The CAPM dates back to the mid-1960s. While the model is tremendously important, there has been a lot of progress over the last 45 years in the understanding of the cross-section of equity returns. It should be clear that the goals of this paper are not to implement full tests of asset pricing models or examine comprehensively the numerous models in the equity literature. Focusing on energy utilities, this paper is an application of the CAPM and two reasonable and relevant alternatives to the problem of cost of equity estimation, using a standard methodology. Our findings show that it is potentially important to go beyond the CAPM for energy utilities. They represent an invitation to further use the advances in the literature on the cross-section of returns to better understand their equity rate of return.

The rest of the paper is divided as follows. The next section presents our sample of energy utilities and reference portfolios. The third, fourth and fifth sections examine the risk premium estimates with the CAPM, the Fama-French model and the Adjusted CAPM, respectively. Each section provides an overview of the model, presents its empirical estimation and results, and discusses the implications of our findings. The last section concludes.

2. Sample Selection and Descriptive Statistics

This section examines the sample of firms and portfolios for our estimation of the cost of equity of energy utilities. We focus on the gas distribution sector to present complete sector-level and firm-level results, but we also consider utilities indexes to ensure the robustness to other utilities. We provide Canadian and American results for comparison, as both energy markets are relatively integrated and investors might expect similar returns. We first discuss sample selection issues and then present descriptive statistics.

2.1. Sample Selection

Two important choices guide our sample selection process. First, we use monthly historical data in order to have sufficient data for estimating the parameters and test statistics, while avoiding the microstructure problems of the stock markets (low liquidity for numerous securities, non-synchronization of transactions, etc.) in higher frequency data.[3] We then annualized our results for convenience. Second, we emphasize reference portfolios (such as sector indexes) over individual firms. Reference portfolios reduce the potentially large noise (or diversifiable risk) in the stock market returns of individual firms. They allow for an increased statistical accuracy of the estimates, an advantage recognized since (at least) Fama and MacBeth (1973), and alleviate the problem that we do not observe the returns on utilities directly and must rely on utility holding companies.

To represent the gas distribution sector in Canada and the U.S., we use a published index and a constructed portfolio for each market. The independently-calculated published indexes are widely available and consider the entire history of firms having belonged to the gas distribution sector. The constructed portfolios use the most relevant firms at present in the gas distribution or energy utility sector. The data collection also allows an examination of the robustness of our results at the firm level. The resulting four gas distribution reference portfolios are described below:

- *DJ_GasDi*: A Canadian gas distribution index published by Dow Jones, i.e. the "Dow Jones Canada Gas Distribution Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *CAindex*: An equally-weighted constructed portfolio formed of 13 Canadian energy utilities, most with activities that are related to the gas distribution sector, i.e. ATCO Ltd., Algonquin Power Income Fund, Canadian Utilities Limited, EPCOR Power, Emera Incorporated, Enbridge Inc., Fort Chicago Energy Partners, Fortis Inc., Gaz Métro Limited Partnership, Northland Power Income Fund, Pacific Northern Gas, TransAlta Corporation and TransCanada Pipelines.[4] Monthly returns (263) are available from February 1985 to December 2006;
- *DJ_GasUS*: A U.S. gas distribution index published by Dow Jones, i.e. the "Dow Jones US Gas Distribution Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *USindex*: An equally-weighted constructed portfolio formed of nine U.S. firms whose activities are heavily concentrated in local gas distribution, i.e. AGL Resources Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Southwest Gas Corp. and WGL Holdings Inc. Monthly returns (407) are available from February 1973 to December 2006.

[3] See Fowler, Rorke and Jog (1979, 1980) for an analysis of these problems in the Canadian stock markets.

[4] We also considered AltaGas Utility Group, Enbridge Income Fund, Westcoast Energy, Nova Scotia Power and Energy Savings Income Fund. We did not retain the first four because they had a returns history of less than 60 months. We eliminated the last one because it is a gas broker and its average monthly return of more than 3% was a statistical outlier. Our results are robust to variations in the formation of the CAindex portfolio, like the inclusion of these five firms or the exclusion of income funds and limited partnerships.

To confirm the validity of our analysis to other energy utilities, we also consider four utilities reference portfolios, which consist of the utilities sector indexes described below:

- *DJ_Util*: A Canadian utilities index published by Dow Jones, i.e. the "Dow Jones Canada Utilities Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *TSX_Util*: A Canadian utilities index published by S&P/TSX, i.e. the "S&P/TSX Utilities Index." The firms in the index are weighted by their market value. Monthly returns (228) are available from January 1988 to December 2006;
- *DJ_UtiUS*: A U.S. utilities index published by Dow Jones, i.e. the "Dow Jones US Utilities Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *FF_Util*: A U.S. utilities index formed by Profs. Fama and French, or the University of Chicago and Dartmouth College, respectively. The firms in the index are weighted by their market value. Monthly returns (407) are available from February 1973 to December 2006.

Depending on their availability, the reference portfolio series have different starting dates. In our econometric estimation, we keep the maximum number of observations for each series. Fama and French (1997) find that such a choice results in costs of equity more precisely estimated and with more predictive ability than costs of equity obtained from rolling five-year estimation windows, a common choice in practice. The data are collected from the Canadian Financial Markets Research Center (CFMRC), Datastream and the web sites of Prof. French[5] and Dow Jones Indexes[6].

2.2. Descriptive Statistics

Descriptive statistics for the monthly returns are presented in Table 1. Panel A shows the results for the 13 Canadian energy utilities and their equally-weighted portfolio (CAindex). Panel B shows the results for nine U.S. gas distribution utilities and their equally-weighted portfolio (USindex). Panel C shows the statistics for Canadian and U.S. indexes for the utilities sector (DJ_Util, DJ_UtilUS, TSX_Util and FF_Util) and the gas distribution sub-sector (DJ_GasDi and DJ_GasUS).[7]

[5] http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html.

[6] http://www.djindexes.com/mdsidx/index.cfm?event=showtotalMarketIndexData&perf=Historical%20Values

[7] The returns from August to November 2001 of the Dow Jones U.S. indexes are strongly influenced by the Enron debacle, which started with the resignation of its CEO, Jeffrey Skilling, on August 14, 2001 and ended with the bankruptcy of the company on December 2, 2001. During those four months, the DJ_GasUS and DJ_UtiUS indices lost 68.9% and 16.2% of their value, respectively. By comparison, the equally-weighted portfolio of U.S. gas distributors (USindex) gained 1.2% and the Fama-French utilities index (FF_Util) lost 6.2 %. In order to soften the impact of that statistical aberration (caused by an unprecedented fraud) on the estimation of the risk premium, the returns from August to November 2001 of DJ_GasUS and DJ_UtilUS are replaced by those of USindex and FF_Util, respectively.

TABLE 1
Descriptive Statistics of Monthly Returns

Variable	N	Mean	St Dev	Min	Max	Brief Description
Panel A: Canadian Energy Utilities						
ATCO	263	0.013	0.067	-0.301	0.279	ATCO Ltd.
Algonqui	108	0.009	0.054	-0.163	0.166	Algonquin Power Income Fund
CanUtili	263	0.012	0.043	-0.107	0.159	Canadian Utilities Limited
EPCOR	114	0.008	0.046	-0.201	0.108	EPCOR Power
Emera	143	0.009	0.043	-0.137	0.115	Emera Incorporated
Enbridge	263	0.011	0.054	-0.365	0.205	Enbridge Inc.
FortChic	107	0.009	0.054	-0.119	0.210	Fort Chicago Energy Partners
Fortis	228	0.013	0.041	-0.134	0.146	Fortis Inc.
GazMetro	166	0.010	0.037	-0.134	0.084	Gaz Métro Limited Partnerships
NorthPow	104	0.011	0.063	-0.202	0.205	Northland Power Income Fund
PacNorth	263	0.010	0.070	-0.400	0.507	Pacific Northern Gas
TransAlt	263	0.009	0.048	-0.217	0.188	TransAlta Corporation
TransCan	258	0.008	0.054	-0.214	0.254	TransCanada Pipelines
CAindex	263	0.010	0.031	-0.130	0.087	Equally-weighted portfolio
Panel B: U.S. Gas Distribution Utilities						
AGL_Res	407	0.013	0.052	-0.138	0.253	AGL Resources Inc.
Atmos	277	0.013	0.063	-0.302	0.269	Atmos Energy Corp.
Laclede	407	0.012	0.056	-0.148	0.374	Laclede Group
NJ_Res	407	0.013	0.063	-0.171	0.577	New Jersey Resources Corp.
Northwes	407	0.012	0.060	-0.236	0.274	Northwest Natural Gas Co.
Piedmont	407	0.013	0.059	-0.188	0.315	Piedmont Natural Gas Co.
SouthJer	407	0.012	0.058	-0.194	0.486	South Jersey Industries
Southwes	407	0.011	0.070	-0.304	0.234	Southwest Gas Corp.
WGL_Hold	407	0.012	0.071	-0.232	0.807	WGL Holdings Inc.
USindex	407	0.012	0.041	-0.121	0.338	Equally-weighted portfolio
Panel C: Sector Indexes						
TSX_Util	228	0.010	0.037	-0.101	0.114	S&P/TSX Utilities Index
DJ_GasDi	180	0.012	0.043	-0.139	0.137	Dow Jones Canada Gas Distribution Index
DJ_Util	180	0.007	0.036	-0.139	0.101	Dow Jones Canada Utilities Index
DJ_GasUS	180	0.012	0.039	-0.120	0.143	Dow Jones US Gas Distribution Index
DJ_UtiUS	180	0.009	0.042	-0.127	0.136	Dow Jones US Utilities Index
FF_Util	407	0.010	0.041	-0.123	0.188	Fama-French US Utilities Index

NOTES: This table presents descriptive statistics on the monthly returns of 13 Canadian utilities and their equally-weighted portfolio (CAindex) in Panel A, of nine U.S. gas distribution utilities and their equally-weighted portfolio (USindex) in Panel B, and on selected utilities sector indexes in Panel C. The columns labelled N, Mean, St Dev, Min and Max correspond respectively to the number of observations, the mean, the standard deviation, the minimum value and the maximum value. The column labelled Brief Description gives the full name of the utility holding companies or the utilities sector indexes.

For the Canadian energy utilities, the monthly average return of all 13 firms is 1.0% with a standard deviation of 3.1%. The Dow Jones Canada Gas Distribution Index, the Dow Jones Canada Utilities Index and the S&P/TSX Utilities Index have mean returns of 1.2%, 0.7% and 1.0%, respectively. The monthly average return of the nine U.S. gas distribution utilities is 1.2% with a standard deviation of 4.1%. The Dow Jones US Gas Distribution Index, the Dow Jones US Utilities Index and the Fama-French U.S. Utilities Index show mean returns of 1.2%, 0.9% and 1.0%, respectively. Correlations between the four gas distribution reference portfolios (not tabulated) are between 0.29 and 0.80. These correlations indicate that the portfolios show some commonality, but are not perfect substitutes. We next start our analysis of the equity risk premium models.

3. Equity Risk Premium with the CAPM

This section examines the use of the Capital Asset Pricing Model (CAPM) for estimating the rate of return for energy utilities. The CAPM is the model the most often associated with the Equity Risk Premium method that is the basis of the rate adjustment formulas of regulatory bodies. We first present the model and its relevant literature. Then we estimate the model for our sample of energy utilities. Finally, we discuss the implications of our findings.

3.1. Model and Literature

The CAPM is a model proposed by Sharpe (1964) and Lintner (1965) in which the expected equity return or cost of equity for a gas utility is given by

$$E(R_{GAS}) = R_f + \beta \times \lambda_m ,$$

where R_f is the risk-free rate, β is the firm's beta or sensitivity to the market returns and λ_m is the market risk premium. In this model, a higher beta results in a higher risk premium.

The CAPM is the best known model of expected return. In spite of its undeniable importance in the field of finance, it has long been rejected by numerous empirical tests in the academic literature. The empirical rejections start with the first tests (Black, Jensen and Scholes, 1972, Fama and MacBeth, 1973, and Blume and Friend, 1973) that find that the relation between beta and average return is flatter than predicted by the model. They continue with the discovery of numerous "anomalies" (like the price-to-earnings effect of Basu, 1977, the size effect of Banz, 1981, etc.). Finally, in the 1990s, based on high-impact articles, including Fama and French (1992, 1993, 1996a and 1996b), Jegadeesh and Titman (1993) and Jagannathan and Wang (1996), the academic profession reaches a relative consensus that the CAPM is not valid empirically. In Canada, like elsewhere in the world, the literature reaches similar conclusions (see Morin, 1980, Bartholdy, 1993, Bourgeois and Lussier, 1994, Elfakhani, Lockwood and Zaher, 1998, L'Her, Masmoudi and Suret, 2002, 2004.).

A complete review of the literature on the problems of the CAPM is beyond the scope of this paper. It is nevertheless important to point out the two characteristics of energy utilities that suggest the CAPM might be problematic in estimating their equity return. First, energy utilities have typically low betas, significantly below one. Second, they are known as value investments, in the sense that they have high earnings-to-price, book-to-market, cash flows-to-price or dividend-to-price ratios. In a summary article requested for a symposium on the 40th anniversary of the CAPM, Fama and French (2004) highlight the result of using the model to estimate the cost of equity capital for firms with these two characteristics:

> "As a result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with

high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low."[8]

As Fama and French (2004) indicate, the low-beta and value characteristics of energy utilities will probably lead the CAPM to estimate a rate of return that is too low. We next examine whether this undervaluation in fact exists in our sample of reference portfolios and utilities.

3.2. Risk Premium Estimates

This section empirically estimates the risk premium with the CAPM using the previously described Canadian and U.S. monthly data.[9] More specifically, we estimate the model using the time-series regression approach pioneered by Black, Jensen and Scholes (1972) with the following equation:

$$R_{GAS,t} - R_{f,t} = \alpha_{GAS} + \beta \times \lambda_{m,t} + \varepsilon_{GAS,t},$$

where $\lambda_{m,t} = R_{m,t} - R_{f,t}$ is the return on the market portfolio in excess of the risk-free return and $\varepsilon_{GAS,t}$ is the mean-zero regression error, at time *t*. In this equation, the CAPM predicts that the alpha (or intercept) is zero ($\alpha_{GAS} = 0$) and the risk premium is $E(R_{GAS,t} - R_{f,t}) = \beta \times E(\lambda_{m,t})$. An alpha different from zero can be interpreted as the risk premium error of the CAPM (see Pastor and Stambaugh, 1999). A positive alpha indicates the CAPM does not prescribe a large enough risk premium compared to its historical value (an underestimation), whereas a negative alpha indicates the CAPM prescribes a risk premium that is too large (an overestimation). It is therefore possible to determine the CAPM risk premium error for energy utilities based on the estimates of the alpha.[10]

We use Hansen's (1982) Generalized Method of Moments technique in order to estimate jointly the parameters α_{GAS} and β of the model and the market risk premium $E(\lambda_{m,t})$. As Cochrane (2001, Section 12.1) shows, this method has the necessary flexibility to correct the results for possible econometric problems in the

[8] Fama and French (2004), p. 43-44.

[9] Our focus is on the estimation of the equity risk premium for energy utilities. To obtain their full cost of equity, we would need to add an appropriate risk-free rate, which could depend on the circumstances. For example, one common choice advocates adding to their equity risk premium the yield on a long-term government bond. But other choices for an appropriate risk-free rate are possible.

[10] The time series regression approach is commonly used when the model factors are returns. Cochrane (2001, Chapter 12) emphasizes that the approach implicitly imposes the restriction that the factors (chosen to fully represent the cross section of returns in the modeling) should be priced correctly in the estimation. While there are other ways to estimate a model like the CAPM, one advantage of the times series regression approach is that it can be easily applied to a restricted set of assets (like energy utilities) as the cross-sectional variations in asset returns are already captured by the correct pricing of the traded factors. Cochrane (2001, Chapter 12) also shows that the approach is identical to a Generalized Least Square cross-sectional regression approach.

data.[11] We take the monthly returns on portfolios of all listed securities weighted by their market value for the market portfolio returns and on the Treasury bills for the risk-free returns.[12] The annualized mean market risk premiums are 5.2% for Canada from February 1985 to December 2006 and 6.0% for the U.S. from February 1973 to December 2006.

Table 2 shows the results of the regressions using each of the four gas distribution reference portfolios. The estimates of the annualized risk premium error (or annualized α_{GAS}), the beta β and the risk premium $\beta \times E(\lambda_{m,t})$ are presented in Panels A, B and C, respectively. For each estimate, the table also shows its standard error, t-statistic and associated p-value.

TABLE 2
CAPM Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	8.43	3.79	2.22	0.028
CAindex	4.52	2.33	1.94	0.053
DJ_GasUS	7.39	3.34	2.21	0.028
USindex	6.23	1.95	3.19	0.002
Panel B: Beta				
DJ_GasDi	0.21	0.11	1.95	0.053
CAindex	0.34	0.07	4.60	<.0001
DJ_GasUS	0.37	0.09	4.16	<.0001
USindex	0.46	0.06	7.37	<.0001
Panel C: Risk Premium				
DJ_GasDi	1.66	1.28	1.30	0.195
CAindex	1.76	1.11	1.58	0.116
DJ_GasUS	2.74	1.46	1.87	0.063
USindex	2.72	1.33	2.04	0.042

NOTES: This table reports the results of the estimation of the CAPM for the gas distribution reference portfolios. Panels A to C look at the annualized risk premium error or alpha (in percent), the market beta and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex.

The estimates in Panel A of Table 2 indicate that the risk premium errors are positive. Hence, the CAPM underestimates the risk premium for the gas distribution reference portfolios. The underestimation is not small – a minimum of 4.52% (for CAindex) and a maximum of 8.43% (for DJ_GasDi) – and is statistically greater than zero for all portfolios. Also, as expected, the underestimation comes with low

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[11] All standard errors and statistical tests have been estimated using the Newey and West (1987) method, which takes account of the potential heteroscedasticity and autocorrelation in the errors of the statistical models.

[12] The data sources are CFMRC (until 2004) and Datastream (thereafter) for the Canadian returns and the web site of Prof. French for U.S. returns.

beta estimates, with values between 0.21 and 0.46 in Panel B. For example, for CAindex, the beta is 0.34 and the annualized risk premium predicted by the CAPM is 1.76%, an underestimation of the historical risk premium $\alpha_{GAS} = 4.52\%$.

To verify the underestimation is not an artifact of the utilization of the reference portfolios and is robust to other energy utilities, Figure 1 shows the risk premium errors for the utilities that make up the CAindex portfolio (Figure 1a), the gas distributors in the USindex portfolios (Figure 1b) and the four utilities reference portfolios (Figure 1c). Once again, the alphas are always positive, with values between 2.1% and 8.9% for the Canadian utilities, between 3.5% and 8.4% for the U.S. gas distributors, and between 2.1% and 5.0% for the utilities reference portfolios. The constantly positive and often significant errors support the notion that the CAPM might not be appropriate for determining the risk premium in the utilities sector.

FIGURE 1
Risk Premium Errors with the CAPM for Various Utilities

Figure 1a: Firms in the CAindex Portfolio

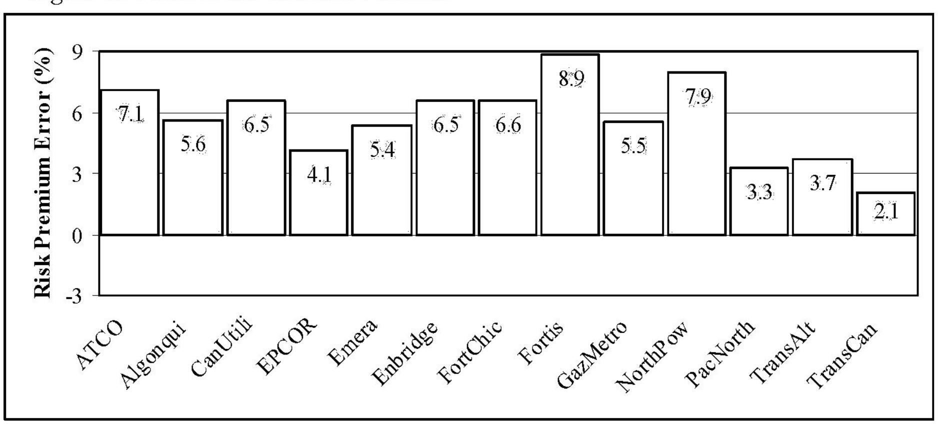


Figure 1b: Firms in the USindex Portfolio

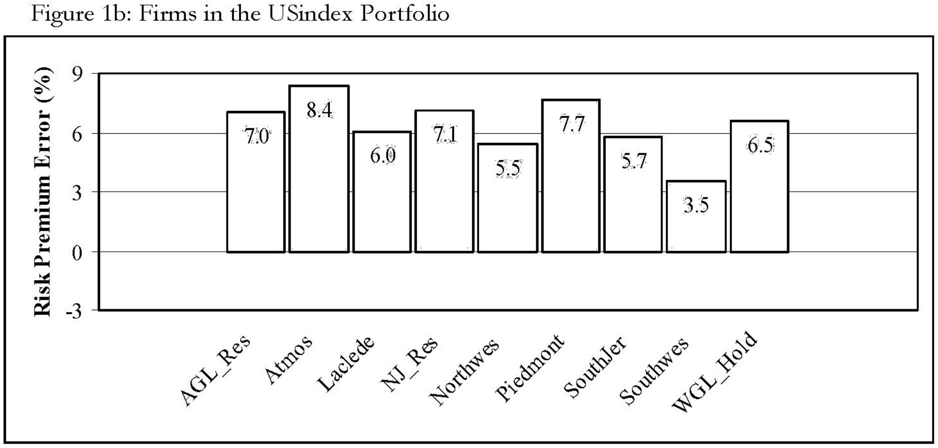
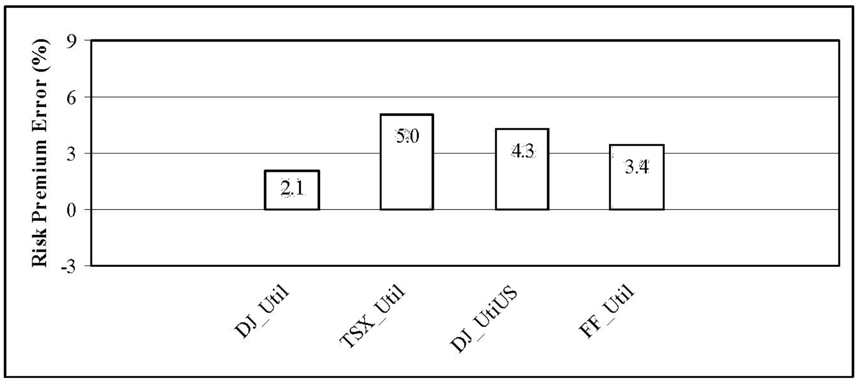


Figure 1c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the CAPM for the Canadian utilities in the CAindex portfolio (Figure 1a), the U.S. gas distributors in the USindex portfolio (Figure 1b) and the utilities reference portfolios (Figure 1c).

3.3. Discussion

Our results show that the CAPM underestimates the risk premium for the gas distribution sub-sector in particular and for the utilities sector in general. This finding is consistent with the empirical literature that finds that the CAPM tends to underestimate the risk premium of securities or sectors associated with low-beta, value and small-cap investments. In the terminology of asset pricing, the returns on energy utilities are "anomalous" with respect to the CAPM. As the application of the model would not be sensible in evaluating the performance of value-type mutual funds, given the related anomaly, it could be unwarranted in evaluating the cost of equity for energy utilities.

While the magnitude of the underestimation for the utilities is large, it is not unexpected. Fama and French (2004) review the evidence on the large CAPM literature for the *full cross-section* of equity returns. Their figures 2 and 3, in particular, illustrate well the findings for portfolios of stocks formed on their beta and their book-to-market ratio value indicator, respectively. In the cross-section of all stock returns, their figure 2 show visually that the CAPM underestimation is about 3% for the lowest beta portfolio (a beta of about 0.6), while its overestimation is about 3% for the highest beta portfolio (a beta of about 1.8). Their figure 3 indicates that the CAPM underestimation is about 5% for the highest book-to-market ratio portfolio, while its overestimation is about 2% for the lowest book-to-market ratio portfolio. As energy utilities are low-beta and value-oriented stocks, our estimates of the CAPM underestimation for this segment are consistent with the evidence from the full cross-section of equity returns.

Our results are related to numerous studies documenting that the CAPM alphas are different from zero. As a consequence of these rejections, finance researchers have considered various models that generalized the CAPM as well as various empirical improvements to the estimates of the CAPM. Based on this literature, we explore two alternative ways of estimating the risk premium of energy utilities in the next two sections.

4. EQUITY RISK PREMIUM WITH THE FAMA-FRENCH MODEL

The CAPM claims that a single factor, the market portfolio return, can explain expected returns. The most natural extension is to take multiple factors into account. Clearly, if factors other than the market return have positive risk premiums that contribute to explaining expected returns, then the inclusion of those factors should provide a better estimate of the risk premium and potentially eliminate the CAPM errors (see Merton, 1973, and Ross, 1976, for formal theoretical justifications). This section considers one of the most common generalization of the CAPM, a multifactor model by Fama and French (1993). We first describe the model and then use it to estimate the risk premium of energy utilities. We finally discuss the interpretation of our findings.

4.1. Model and Literature

The Fama-French model is a three-factor model developed to capture the anomalous returns associated with small-cap, value and growth portfolios by including risk premiums for size and value. For a gas utility, the expected equity return is given by

$$E(R_{GAS}) = R_f + \beta \times \lambda_m + \beta_{SIZE} \times \lambda_{SIZE} + \beta_{VALUE} \times \lambda_{VALUE},$$

where R_f is the risk-free rate, β, β_{SIZE} and β_{VALUE} are respectively the firm's market, size and value betas, and λ_m, λ_{SIZE} and λ_{VALUE} are respectively the market, size and value risk premiums. The three betas represent sensitivities to the three sources of risk, and the higher are their values, the higher is a firm's risk premium. In cases when the size and value risk factors are not relevant, then the Fama-French model reduces to the CAPM. Theoretical justifications for the size and value premiums are provided by Berk, Green and Naik (1999), Gomez, Kogan and Zhang (2003), and Carlson, Fisher and Giammarino (2004). Fama and French (1993, 1996a) are the two of the most influential empirical tests of the model.

Like the CAPM, the Fama-French model has been used in applications ranging from performance measurement to abnormal return estimation and asset valuation. For the calculation of the cost of equity capital, the model is studied by, among others, Schink and Bower (1994), Fama and French (1997), and Pastor and Stambaugh (1999). It has also proven to be relevant for explaining stock market returns in most countries where it has been examined. For example, in Canada, the model is validated by Elfakhani, Lockwood and Zaher (1998) and L'Her, Masmoudi and Suret (2002). Given that energy utilities are associated with value investments, the Fama-French model has the potential to improve the estimation of their rates of returns. We next assess this possibility for our sample of reference portfolios and utilities.

4.2. Risk Premium Estimates

The risk premium with the Fama-French model is estimated with a methodology that is similar to the one followed for the CAPM using the following equation:

$$R_{GAS,t} - R_{f,t} = \alpha_{GAS}^{FF} + \beta \times \lambda_{m,t} + \beta_{SIZE} \times \lambda_{SIZE,t} + \beta_{VALUE} \times \lambda_{VALUE,t} + \upsilon_{GAS,t},$$

where $\lambda_{m,t} = R_{m,t} - R_{f,t}$ is the return on the market portfolio in excess of the risk-free return, $\lambda_{SIZE,t} = R_{SMALL,t} - R_{LARGE,t}$ is the return on a small-cap portfolio in excess of the return on a large-cap portfolio, $\lambda_{VALUE,t} = R_{VALUE,t} - R_{GROWTH,t}$ is the return on a value portfolio in excess of the return on a growth portfolio and $\upsilon_{GAS,t}$ is the mean-zero regression error, at time *t*. The alpha α_{GAS}^{FF} is still interpreted as the risk premium error. The three beta parameters give the sensitivities to the market, size and value factors. Finally, $\beta \times E(\lambda_{m,t}) + \beta_{SIZE} \times E(\lambda_{SIZE,t}) + \beta_{VALUE} \times E(\lambda_{VALUE,t})$ represents the risk premium from the Fama-French model.

The data for the market portfolio returns and the risk-free returns are the same used in the CAPM estimation. For the Canadian regressions, the small-cap portfolio returns are from a portfolio of all listed securities weighted equally whereas the large-cap portfolio returns are from a portfolio of all listed securities weighted by their market value.[13] The value and growth portfolios are determined from the earnings-to-price ratio. Specifically, the value (growth) portfolio contains firms having an earnings/price ratio in the highest (lowest) 30%.[14] For U.S. regressions, the size and value premiums are the Fama and French (1993, 1996a) SMB and HML variables, which are computed from market capitalization (size) and book-to-market ratio (value).[15] The annualized mean size and value risk premiums are respectively 8.9% and 6.4% for Canada from February 1985 to December 2006 and 2.7% and 6.0% for the U.S. from February 1973 to December 2006.

Table 3 presents the results of the estimates of the coefficients and the risk premium with the Fama-French model for the four gas distribution reference portfolios previously described. Panel A shows that the annualized risk premium errors are still positive for the four portfolios, ranging from 0.31% (for USindex) to 4.45% (for DJ_GasDi), but the underestimation is now statistically negligible. Panel D confirms that the inclusion of the value risk premium is instrumental in the reduction of the errors. The value betas are highly significant, with values between 0.30 and 0.71. The size betas (Panel C) are low and often not statistically different from zero, whereas the market betas (Panel B) are 0.54 on average. The estimated risk premiums vary between 4.23% and 8.83%.

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13 These indexes are taken from CFMRC for returns up to 2004 and then completed by the returns of the S&P/TSX Composite Index and the MSCI Barra Smallcap Index, respectively.

14 Data come from the web site of Prof. French, who also provides specific instructions on the composition of the portfolios. The site gives returns for value and growth portfolios based on four indicators – earnings-to-price, book-to-market, cash flows-to-price and dividend-to-price. Fama and French (1996a) show that these indicators contain the same information about expected returns. Fama and French (1998) confirm the relevance of these indicators in explaining the returns in 12 major international financial markets and emerging financial markets. We chose the earnings-to-price indicator because it is more effective in capturing the premium of value securities compared to growth securities in Canada (see Bartholdy, 1993, and Bourgeois and Lussier, 1994). The indicator book-to-market is less effective in Canada because the value effect is mainly concentrated in more extreme portfolios (highest and lowest 10%) than in those available on the site (see L'Her, Masmoudi and Suret, 2002).

15 Data again come from the web site of Prof. French. Detailed instructions on the composition of the SMB and HML variables are also provided.

TABLE 3
Fama-French Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	4.45	3.11	1.43	0.155
CAindex	2.04	1.85	1.11	0.270
DJ_GasUS	1.31	3.01	0.43	0.665
USindex	0.31	1.80	0.17	0.863
Panel B: Beta				
DJ_GasDi	0.41	0.08	5.06	<.0001
CAindex	0.48	0.05	10.38	<.0001
DJ_GasUS	0.63	0.07	9.64	<.0001
USindex	0.64	0.06	11.18	<.0001
Panel C: Size Beta				
DJ_GasDi	-0.01	0.08	-0.11	0.912
CAindex	-0.02	0.05	-0.51	0.613
DJ_GasUS	0.00	0.09	0.04	0.971
USindex	0.20	0.07	2.9	0.004
Panel D: Value Beta				
DJ_GasDi	0.33	0.06	5.12	<.0001
CAindex	0.30	0.04	7.64	<.0001
DJ_GasUS	0.59	0.13	4.41	<.0001
USindex	0.71	0.10	7.21	<.0001
Panel E: Risk Premium				
DJ_GasDi	5.64	1.78	3.17	0.002
CAindex	4.23	1.52	2.78	0.006
DJ_GasUS	8.83	2.32	3.81	0.000
USindex	8.64	2.16	4	<.0001

NOTES: This table reports the results of the estimation of the Fama-French model for the gas distribution reference portfolios. Panels A to E look at the annualized risk premium error or alpha (in percent), the market beta, the size beta, the value beta and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex. The annualized mean size risk premiums for their corresponding sample period are 12.4% for DJ_GasDi, 8.9% for CAindex, 2.7% for DJ_GasUS and 2.7% for USindex. The annualized mean value risk premiums for their corresponding sample period are 7.4% for DJ_GasDi, 6.4% for CAindex, 6.9% for DJ_GasUS and 6.0% for USindex.

Figure 2 compares the Fama-French and CAPM results. Figure 2a illustrates the risk premium errors of the two models, while Figure 2b shows their explanatory power given by the adjusted R^2. The errors have substantially fallen with the Fama-French model for all reference portfolios. Furthermore, the Fama-French model explains a much larger proportion of the variation in the reference portfolio returns.

FIGURE 2
Comparison of the Fama-French and CAPM Results

Figure 2a: Risk Premium Errors

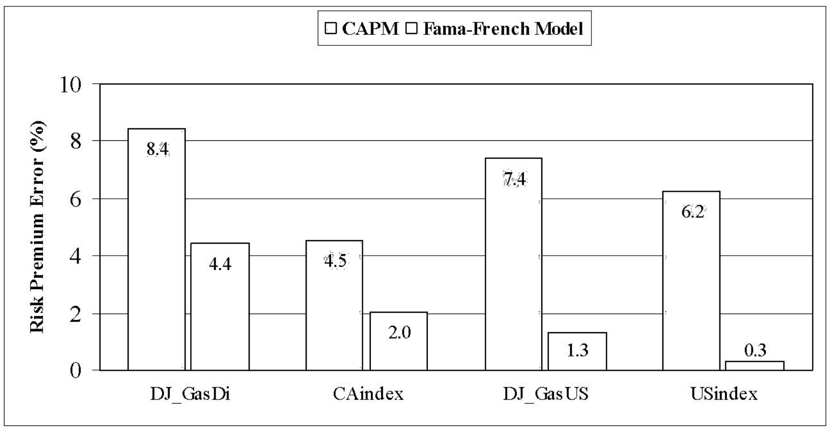
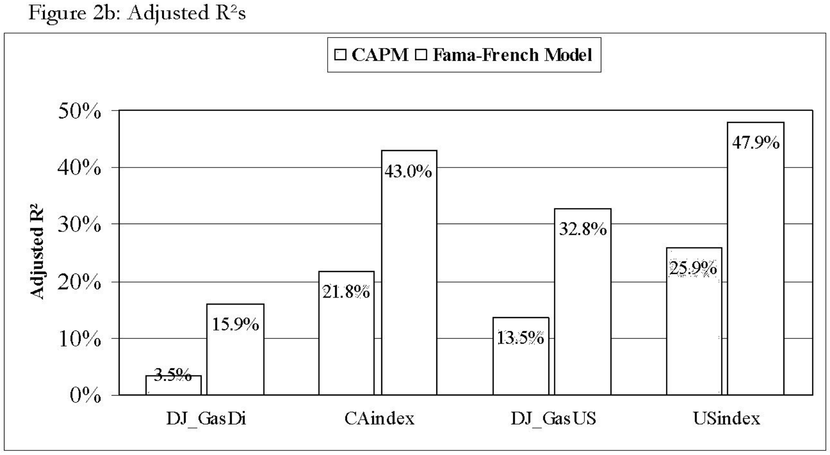


Figure 2b: Adjusted R^2s



NOTES: This figure compares the results of the CAPM (gray bars) and the Fama-French model (white bars) in terms of annualized risk premium errors (or alphas) (Figure 2a) and adjusted R^2 (Figure 2b) for the gas distribution reference portfolios.

Figures 3 and 4 present the risk premium errors and the value betas, respectively, for the utilities that make up the CAindex portfolios (Figures 3a and 4a), the gas distributors in the USindex portfolios (Figures 3b and 4b) and the four utilities reference portfolios (Figures 3c and 4c). A comparison of Figure 3 with Figure 1 shows that the risk premium errors have decreased in all cases. None of the errors are now significantly different from zero. Figure 4 confirms that the reductions in the risk premium errors are caused by the inclusion of the value risk premium. All value betas are greater than 0.23 and statistically significant. For example, the TSX_Util portfolio has a value beta of 0.41 that contributes to reduce its risk premium error from 5.0% with the CAPM to 0.7% with the Fama-French model.

FIGURE 3
Risk Premium Errors with the Fama-French Model for Various Utilities

Figure 3a: Firms in the CAindex Portfolio

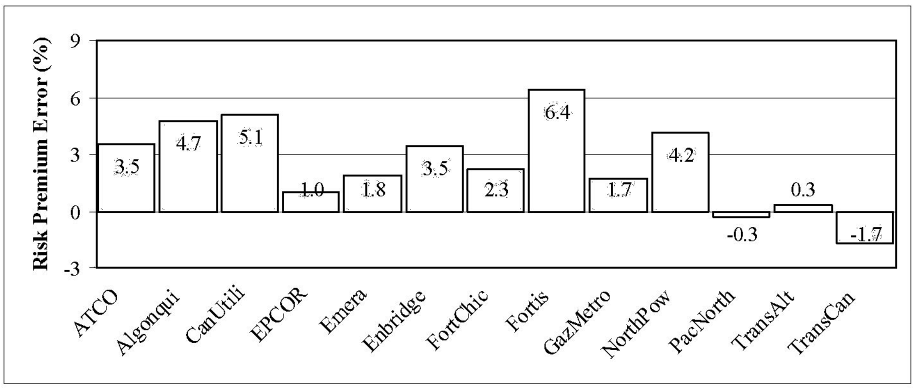


Figure 3b: Firms in the USindex Portfolio

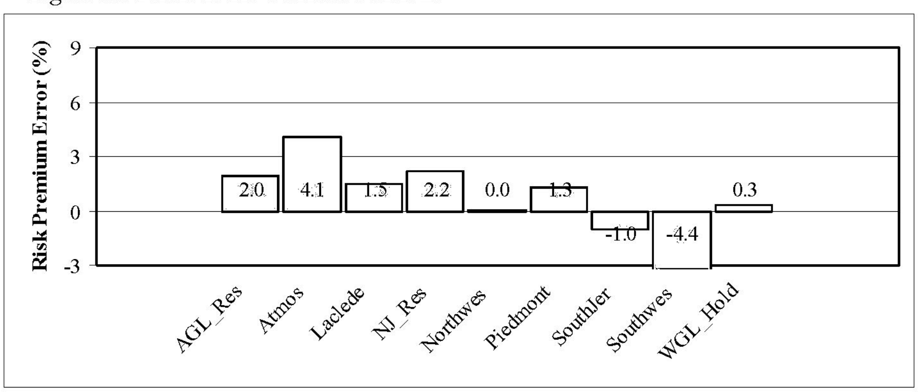
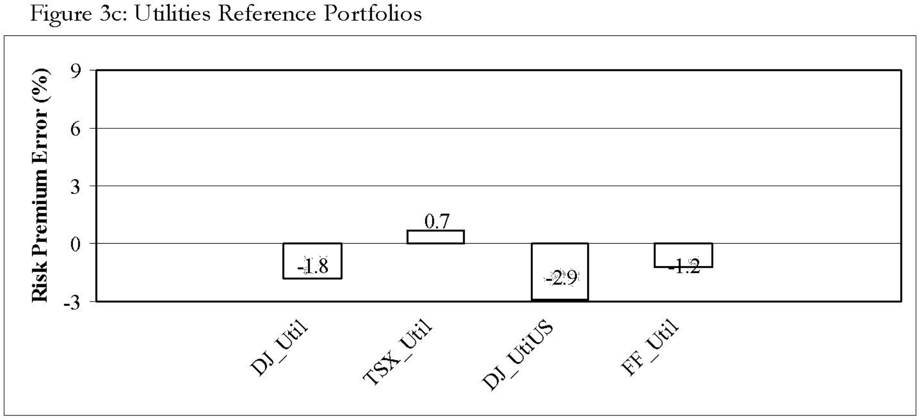


Figure 3c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Fama-French model for the Canadian utilities in the CAindex portfolio (Figure 3a), the U.S. gas distributors in the USindex portfolio (Figure 3b) and the utilities reference portfolios (Figure 3c).

FIGURE 4
Value Betas for Various Utilities

Figure 4a: Firms in the CAindex Portfolio

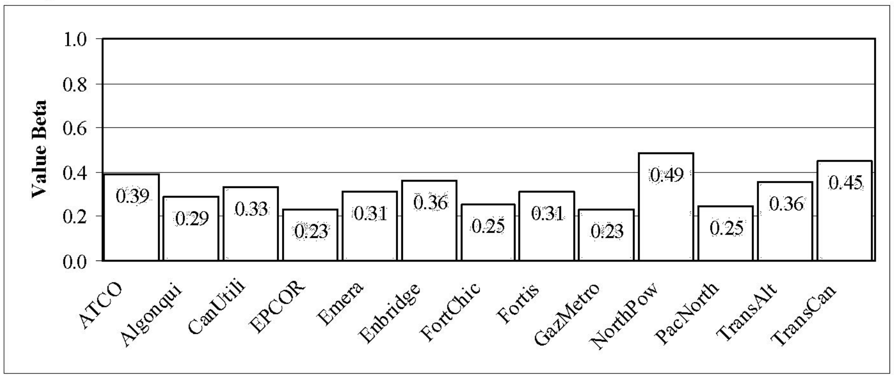


Figure 4b: Firms in the USindex Portfolio

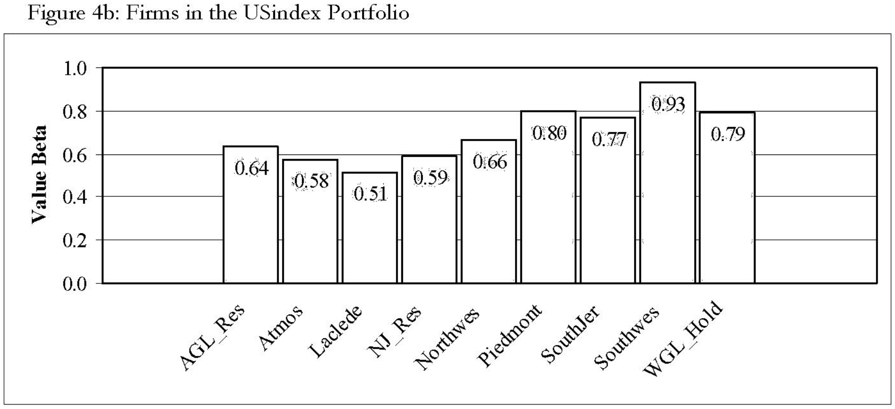
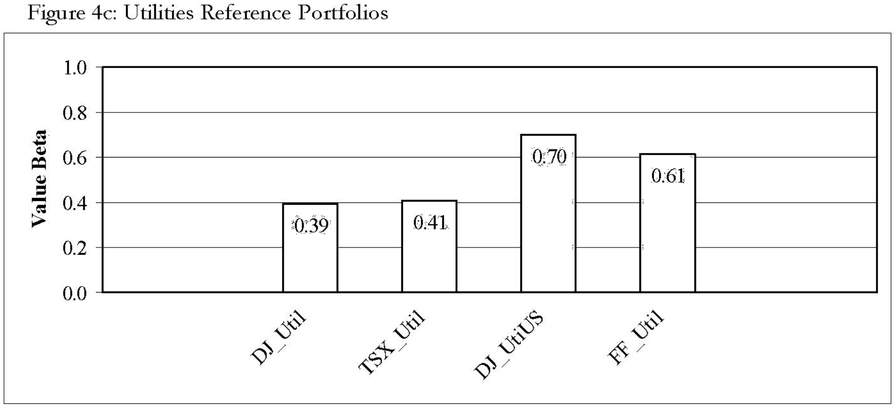


Figure 4c: Utilities Reference Portfolios



NOTES: This figure shows the value betas in the Fama-French model for the Canadian utilities in the CAindex portfolio (Figure 4a), the U.S. gas distributors in the USindex portfolio (Figure 4b) and the utilities reference portfolios (Figure 4c).

4.3. Discussion

Our results support the notion that the Fama-French model is well suited to estimate the risk premium for energy utilities, consistent with the findings of Schink and Bower (1994). We obtain lower risk premium errors with the Fama-French model than with the CAPM and significant value betas, similar to the results reported by Schink and Bower (1994), Fama and French (1997) and Pastor and Stambaugh (1999).

While the model is being increasingly considered in practice, an often mentioned limitation is that the economic interpretation of the size and value premiums is still under debate. On one side, starting with Fama and French (1993), the size and value factors are presented as part of a rational asset pricing model, where they reflect either state variables that predict investment opportunities following the theory of Merton (1973), or statistically useful variables to explain the returns following the theory of Ross (1976). On the other side, as first advocated by Lakonishok, Shleifer and Vishny (1994), the size and value factors are thought to be related to investors' irrationality in the sense that large-cap and growth stocks tend to be glamorized whereas small-cap and value stocks tend to be neglected. There is a vast literature on both sides of this debate.[16]

While the debate is important to improve our understanding of capital markets, Stein (1996) demonstrates that the theoretical interpretation of the model is not relevant to its application to determine the cost of capital. On one side, if the Fama-French model is rational, then the size and value factors capture true risks and should be accounted for in the risk premiums of energy utilities. On the other side, if the size and value factors are irrational, then the significant value betas of energy utilities indicate that they are neglected or undervalued firms. In this case, Stein (1996) shows that rational firms should not undertake a project that provides an expected return lower than the return estimated by the potentially irrational Fama-French model. They are better off in rejecting the project and simply buying back their own shares for which they expect an inflated future return because of the undervaluation. Thus, the potentially irrational Fama-French estimates serve as the appropriate hurdle rate for project investments. Hence, for both interpretations, the equity cost of capital of energy utilities generated by the Fama-French model is a useful guideline of a fair rate of return for regulators.

Arguably, the Fama-French model is one of the most widely used models of expected returns in the academic finance literature (Davis, 2006). Nevertheless, the literature on the cross-section of equity returns has identified numerous other factors that could be relevant in the multifactor approach. For examples, other influential factors include the labor income factor of Jagannathan and Wang (1996), the momentum factor of Jegadeesh and Titman (1993) and Carhart (1997), the liquidity factor of Pastor and Stambaugh (2003) and the idiosyncratic volatility factor of Ang *et al.* (2006, 2009). These advances in the literature on the cross-section of returns could eventually lead to a better understanding of the equity risk premium

[16] A third interpretation, following Lo and MacKinlay (1990) and Kothari, Shanken and Sloan (1995), is that the results of the Fama-French model are spurious, due to biases like data snooping or survivorship. However, the fact that similar size and value premiums have been found in countries outside the U.S. has rendered this explanation less appealing.

for energy utilities.[17] The next section looks at a second approach that goes beyond the CAPM to estimate the equity risk premium.

5. Equity Risk Premium with the Adjusted CAPM

This section considers two empirical adjustments to the CAPM estimates proposed in the academic literature to account for their deficiencies. We call the CAPM with the addition of the two modifications the "Adjusted CAPM". Unlike the CAPM and the Fama-French model, the Adjusted CAPM is not an equilibrium model of expected returns. It contains adjustments to the CAPM that are empirically justified in a context where the known difficulties of a theoretical model need to be lessened for improved estimation. We first introduce the Adjusted CAPM. Then we implement it to estimate the risk premium of energy utilities. We finally offer a brief discussion of our findings.

5.1. Model and Literature

The Adjusted CAPM is based on the CAPM but provides more realistic estimates of the rate of return by considering the empirical problems of the CAPM. More specifically, the Adjusted CAPM is a model in which the expected equity return of a gas utility is arrived at by

$$E(R_{GAS}) = R_f + \alpha_{GAS} \times \left(1 - \beta^{Adj}\right) + \beta^{Adj} \times \lambda_m .$$

Compared to the CAPM, this equation incorporates a modification to take into account that estimated betas can be adjusted for better predictive power and a modification to take account of the fact the alpha (risk premium error) is high for low-beta value-oriented firms in the CAPM.

The first modification originates from the works of Blume (1971, 1975). Blume (1971) examines historical portfolio betas over two consecutive periods and finds that the historical betas, from one period to another, regress towards one, the average of the market. He also shows that the historical betas adjusted towards one predict future betas better than unadjusted betas. Blume (1975) builds a historical beta adjustment model to capture the tendency to regress towards one. He discovers that the best adjustment is to use a beta equal to $0.343 + 0.677 \times \beta^{His}$, a finding that led to the concept of "adjusted beta". Merrill Lynch, which popularized the use of adjusted betas based on Blume (1975)'s results, advocates the adjustment $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. Merrill Lynch's adjusted beta, now widely used in practice, represents a weighted-average between the beta of the market and the historical beta, with a two-thirds weighting on the historical beta.

The second adjustment is initially proposed by Litzenberger, Ramaswamy and Sosin (1980), who consider solutions to the problem that the CAPM gives a cost of equity capital with a downward bias for low beta firms, as discussed in section 3.1. They note that one way of remedying the problem is to add a bias correction to the CAPM risk premium. To be effective, the correction must take account of the

[17] Some of the documented effects, like momentum, are short-lived. Hence, their related factor might be irrelevant for estimates of the cost of equity capital.

importance of the risk premium error and the level of the firm's beta because these two elements influence the magnitude of the problem. To do this for low beta securities, Litzenberger, Ramaswamy and Sosin (1980) propose the bias correction $\alpha_{GAS} \times (1-\beta)$. As desired, the correction increases with the risk premium error of the CAPM, and decreases with the beta. The correction is nil for a firm for which the CAPM already works well (when $\alpha_{GAS} = 0$) or for a firm having a beta of one, two cases where the CAPM produces a fair rate of return on average. Morin (2006, Section 6.3) presents an application of this adjustment in regulatory finance through a model he calls the empirical CAPM.

In summary, the two modifications incorporated in the Adjusted CAPM involve first using the adjusted beta instead of the historical beta and second including the bias correction in the risk premium calculation. Considering the documented usefulness of the two adjustments, the Adjusted CAPM has the potential to estimate a reasonable risk premium for the energy utilities.

5.2. Risk Premium Estimates

To compute the Adjusted CAPM estimates for our utilities, the starting point is the estimates of the CAPM of Section 3.2, given in Table 2. The beta estimates are now understood as the unadjusted historical betas β^{His}. The gas utility risk premium with the Adjusted CAPM can then be expressed as

$$\alpha_{GAS} \times \left(1-\beta^{Adj}\right) + \beta^{Adj} \times E\left(\lambda_{m,t}\right),$$

where $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. The Adjusted CAPM risk premium error is arrived at by

$$\alpha_{GAS}^{Adj} = E\left(R_{GAS,t} - R_{f,t}\right) - \left[\alpha_{GAS} \times \left(1-\beta^{Adj}\right) + \beta^{Adj} \times E\left(\lambda_{m,t}\right)\right].$$

Table 4 shows the Adjusted CAPM estimates using the four gas distribution reference portfolios. The estimates of the risk premium error α_{GAS}^{Adj}, the adjusted beta β^{Adj}, the bias correction $\alpha_{GAS} \times \left(1-\beta^{Adj}\right)$ and the risk premium are shown in Panels A, B, C and D, respectively. The risk premium errors are still positive for the four portfolios, with values ranging from 1.39% (for CAindex) to 2.89% (for USindex), but the underestimation is only significant for USindex. The reduction in errors comes from the use of adjusted betas, which are 0.56 on average, and the bias corrections, which are 2.96% on average. Lastly, the risk premiums vary between 4.88% and 8.27%, findings comparable to the estimates obtained with the Fama-French model.

TABLE 4
Adjusted CAPM Risk Premium Estimates
for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	1.82	2.00	0.91	0.365
CAindex	1.39	1.54	0.9	0.366
DJ_GasUS	2.68	1.97	1.36	0.176
USindex	2.89	1.37	2.11	0.035
Panel B: Adjusted Beta				
DJ_GasDi	0.47	0.07	6.69	<.0001
CAindex	0.56	0.05	11.38	<.0001
DJ_GasUS	0.58	0.06	9.84	<.0001
USindex	0.64	0.04	15.44	<.0001
Panel C: Bias Correction				
DJ_GasDi	4.46	2.28	1.96	0.052
CAindex	1.99	1.10	1.81	0.071
DJ_GasUS	3.12	1.61	1.94	0.054
USindex	2.26	0.77	2.94	0.004
Panel D: Risk Premium				
DJ_GasDi	8.27	2.71	3.05	0.003
CAindex	4.88	2.11	2.31	0.021
DJ_GasUS	7.45	2.52	2.96	0.004
USindex	6.05	1.89	3.21	0.002

NOTES: This table reports the results of the estimation of the Adjusted CAPM for the gas distribution reference portfolios. Panels A to D look at the annualized risk premium error or alpha (in percent), the adjusted market beta, the bias correction and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex.

Figure 5 shows the risk premium errors for the utilities that make up the CAindex portfolios (Figure 5a), the gas distributors in the USindex portfolios (Figure 5b) and the four utilities reference portfolios (Figure 5c). The errors are generally insignificant and a comparison with Figure 1 indicates that they have decreased considerably for all portfolios. For example, for the TSX_Util portfolio, the error is down from 5.0% with the CAPM to 0.9% with the Adjusted CAPM.

FIGURE 5
Risk Premium Errors with the Adjusted CAPM for Various Utilities

Figure 5a: Firms in the CAindex Portfolio

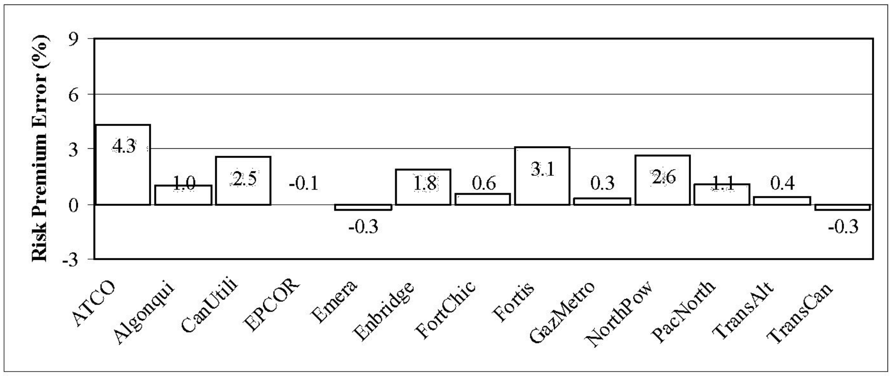


Figure 5b: Firms in the USindex Portfolio

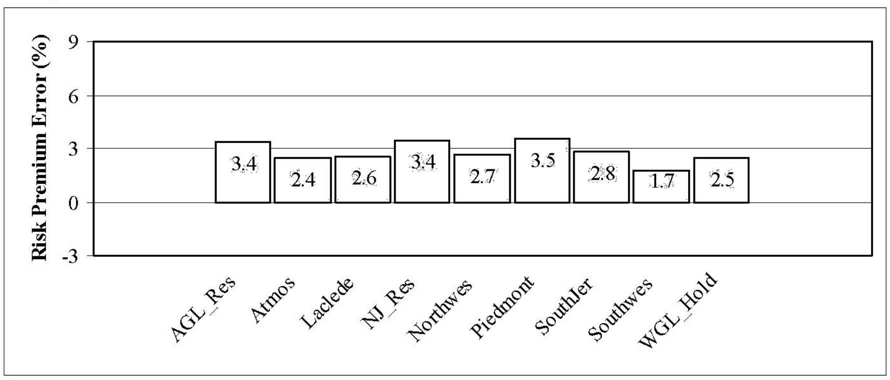
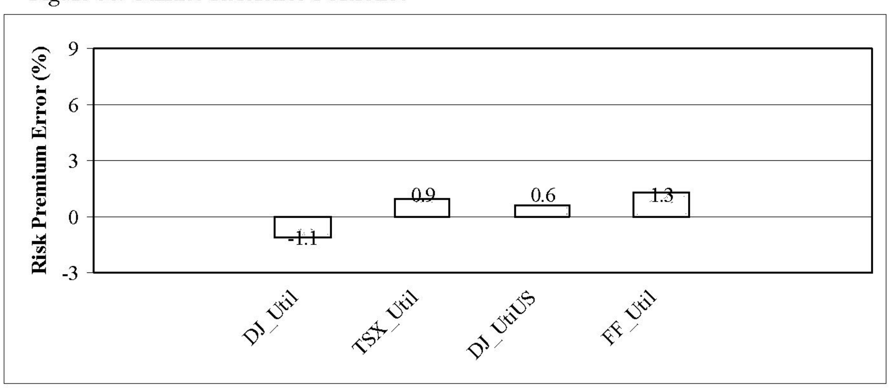


Figure 5c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Adjusted CAPM for the Canadian utilities in the CAindex portfolio (Figure 5a), the U.S. gas distributors in the USindex portfolio (Figure 5b) and the utilities reference portfolios (Figure 5c).

5.3. Discussion

Our results support the validity of the Adjusted CAPM for determining the rate of return on energy utilities. While its risk premium estimates are in the same range as the Fama-French estimates, it arrives at its results from a different perspective. The Fama-French model advocates the use of additional risk factors to reduce the CAPM risk premium errors. The Adjusted CAPM, through its bias correction, effectively estimates the risk premium as a weighted-average of the CAPM risk premium and the realized historical risk premium, with a weighting of beta on the former.

The Adjusted CAPM thus recognizes that the CAPM is an imperfect model that can be improved with the information contained in the historical returns. Pastor and Stambaugh (1999) propose a similar strategy by demonstrating how to estimate the cost of equity by using Bayesian econometrics to incorporate the CAPM risk premium error (or alpha) in an optimal manner based on the priors of the evaluator. Consistent with our results, they also show evidence of higher costs of equity for energy utilities using their technique than using the CAPM alone.[18] As the Adjusted CAPM does not require additional risk factors like size and value, the model might be easier to interpret for regulators already familiar with the standard CAPM in their decisions.

6. Conclusion

It is difficult to overstate the importance of the evaluation of the expected rate of return in finance. For a firm's management group, the expected rate of return on equity (or the equity cost of capital) is central to its overall cost of capital, i.e. the rate used to determine which projects will be undertaken. For portfolio managers, the expected rate of return on equity is an essential ingredient in portfolio decisions. For regulatory bodies, the expected return on equity is the basis for determining the fair and reasonable rate of return of a regulated enterprise. This paper is interested in evaluating the rate of return in the context of regulated energy utilities.

The academic literature contains numerous theories for determining the expected rate of return on equity. As those theories are based on simplified assumptions of the complex world in which we live, they cannot be perfect. Even if the theoretical merit of the different models can be debated, the determination of the most valid approach to explain the financial markets really becomes an empirical question – it is necessary to answer the question "which theory best explains the information about actual returns?" This paper empirically examines the validity of the model the most often used in the rate adjustment formula of regulatory bodies, the CAPM, one of the most prominent academic alternatives, the Fama-French model, and a version of the CAPM modified to account for some of its empirical deficiencies, the Adjusted CAPM.

Our empirical results show that the risk premiums for energy utilities estimated with the CAPM are rejected as too low compared to the historical risk premiums.

[18] Pastor and Stambaugh (1999) obtain risk premiums that vary between the CAPM estimates, when they assume that there is zero prior uncertainty on the CAPM, and the historical estimates, when they assume that there is infinite prior uncertainty on the CAPM. Our bias correction corresponds approximately to a prior uncertainty on the CAPM between 3% and 6% in their setup.

The rejections are related to the well-documented CAPM underestimation of the average returns of low-beta firms and value firms. The Fama-French model and the Adjusted CAPM appear statistically better specified, as we cannot reject the hypothesis that their risk premium errors are equal to zero. They suggest equity risk premiums for gas distribution utilities between 4% and 8%. Overall, our findings demonstrate that models that go beyond the CAPM have the potential to improve the estimation of the cost of equity capital of energy utilities. They are thus interesting avenues for regulators looking to set fair and reasonable equity rates of return.

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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	G. Nanette Thompson, Chair Bernie Smith Patricia M. DeMarco Will Abbott James S. Strandberg

In the Matter of the Correct Calculation and Use of Acceptable Input Data To Calculate the 1997, 1998, 1999, 2000, 2001, and 2002 Tariff Rates for the Intrastate Transportation of Petroleum over the Trans Alaska Pipeline System Filed by AMERADA HESS PIPELINE CORPORATION; ARCO TRANSPORTATION ALASKA, INC.; BP PIPELINES (ALASKA) INC.; EXXON PIPELINE COMPANY; MOBIL ALASKA PIPELINE COMPANY; EXXONMOBIL PIPELINE COMPANY; PHILLIPS ALASKA PIPELINE CORPORATION; UNOCAL PIPELINE COMPANY; PHILLIPS TRANSPORTATION ALASKA, INC.; and WILLIAMS ALASKA PIPELINE COMPANY, L.L.C., and the Protest by TESORO ALASKA PETROLEUM COMPANY of the 1997 and 1999 Tariff Rates	P-97-4 ORDER NO. 151
In the Matter of the Petition of TESORO ALASKA PETROLEUM COMPANY for an Investigation into the Amounts Collected by AMERADA HESS PIPELINE CORPORATION; ARCO TRANSPORTATION ALASKA, INC.; BP PIPELINES (ALASKA) INC.; EXXON PIPELINE COMPANY; MOBIL ALASKA PIPELINE COMPANY; PHILLIPS ALASKA PIPELINE CORPORATION; and UNOCAL PIPELINE COMPANY for Dismantling, Removal, and Restoration of the Trans Alaska Pipeline System	P-97-7 ORDER NO. 110

ORDER REJECTING 1997,1998,1999 AND 2000 FILED TAPS RATES; SETTING JUST AND REASONABLE RATES; REQUIRING REFUNDS AND FILINGS; AND OUTLINING PHASE II ISSUES

BY THE COMMISSION:

ORDER REJECTING 1997,1998,1999 AND 2000 TAPS RATES; SETTING JUST AND REASONABLE RATES; REQUIRING REFUNDS AND FILINGS; AND OUTLINING PHASE II ISSUES

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I. DECISION SUMMARY

Two petroleum companies operating in Alaska, Tesoro[1] and Williams,[2] assert that the 1997 rates for transporting North Slope oil to their Alaska refineries over the Trans Alaska Pipeline System (TAPS) exceed the reasonable costs of transportation. To investigate their allegations, we suspended all post-1997 intrastate TAPS rates[3] filed by the TAPS Carriers,[4] and held an evidentiary hearing.

The Alaska Pipeline Act requires that oil pipelines operate as common carriers and gives this Commission the responsibility of setting just and reasonable rates for intrastate transportation.[5] After careful review of the record we conclude in this order that the 1997-2000 filed intrastate TAPS rates do not satisfy the AS 42.06

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[1]Tesoro Alaska Company.

[2]Williams Alaska Petroleum Company.

[3]*Re Amerada Hess Pipeline Corp.,* Order P-86-2(61)/P-92-2(30)/P-94-1(36)/P-95-1(16)/P-97-4(1)/P-97-5(1)/P-97-6(1)/P-97-7(1), dated June 27, 1997; *Re Exxon Valdez* Litigation *and Settlement Costs*, Order P-94-1(46)/P-95-1(26)/P-97-4(12)/P-97-6(11)/P-97-7(11)/P97-9(5), dated December 26, 1997; *Re Exxon Valdez Litigation and Settlement Costs*, Order P-94-1(54)/P-95-1(33)/P-97-4(35)/P-97-6(20)/P-97-7(21), dated December 28, 1988; *Re Exxon Valdez Litigation and Settlement Costs,* Order P-94-1(75)/P-97-4(64)/P-97-6(41)/P-97-7(46), dated December 20, 1999; *Re Amerada Hess Pipeline Corp.*, Order P-94-1(101)/P-97-4(105)/P-97-6(66)/P-97-7(72), dated December 29, 2000; *Re Amerada Hess Pipeline Corp.*, Order P-94-1(111)/P-97-4(144)/P-97-6(78)/P-97-7(103), dated December 20, 2001.

[4]The TAPS Carriers are Amerada Hess Pipeline Corporation, BP Pipelines (Alaska) Inc., ExxonMobil Pipeline Company, Phillips Transportation Alaska, Inc. and Unocal Pipeline Company (collectively the Indicated Taps Carriers). Williams Alaska Pipeline Company, L.L.C. acquired the pipeline interest of Mobil Alaska Pipeline Company in TAPS effective July 1, 2000. Although Williams Alaska Pipeline Company, L.L.C. is a TAPS Carrier closely aligned with the Indicated TAPS Carriers and has adopted the testimony and exhibits of the Indicated TAPS Carriers for the purposes of this proceeding, Williams Alaska Pipeline Company, L.L.C. has carefully maintained its individual party status throughout this proceeding. Therefore, we refer to all of the TAPS Carriers except Williams Alaska Pipeline Company, L.L.C. as the Indicated Carriers and to all of the TAPS Carriers as the Carriers. Each of the Carriers holds separate certificates of public convenience and necessity. As a result, each Carrier files separate rates for transportation on TAPS for each year. The Carriers are subsidiary corporations of most of the producers who ship oil on the TAPS.

[5]AS 42.06.140, AS 42.06.410(a).

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requirement that pipeline rates be just and reasonable, set new 1997-2000 rates and order filings so that we can set rates for 2001 and subsequent years.

The Trans Alaska Pipeline System carries oil from the largest oil field on the North American continent, Prudhoe Bay, on the North Slope of Alaska over 800 miles across tundra, mountains and rivers to the freshwater port of Valdez, Alaska. During Prudhoe Bay's peak production years, the pipeline carried two billion barrels each day. Constructing TAPS was and remains the most ambitious pipeline construction project in United States history. Planning and construction began in 1968 and the first oil flowed through the pipeline in 1977.

Over ninety percent of the oil produced in Alaska is carried by tankers to markets on the west coast of the United States. The Federal Energy Regulatory Commission (FERC) is responsible for approving rates for interstate shipments. Throughout the pipeline's history, some oil has been removed from the pipeline in Alaska and processed for sale in local markets.[6] The Regulatory Commission of Alaska sets just and reasonable rates for intrastate transportation based on the costs reasonably incurred in transporting oil from the North Slope to destinations in Alaska. Just and reasonable intrastate transportation rates are important for insuring continuing

[6]Some oil is delivered to intermediate points along the pipeline route within Alaska: 1) to the Golden Valley interconnection outside of Fairbanks, Alaska for further transportation to the Williams and Petro Star refineries in North Pole and 2) to Petro Star refinery outside of Valdez. We have jurisdiction over the tariffed rates charged for intrastate shipments. AS 42.06. Therefore, rather than determining the rate for 1,151,000 barrels per day our decision affects the rate applied to only 87,000 barrels per day of the TAPS oil. RGV-14 Schedule 1.

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development of the state's oil resources and insuring that Alaskans have the opportunity to benefit from development of their natural resources.[7]

After prolonged litigation about the appropriate rates for shipments on the TAPS, the TAPS Carriers signed interstate and intrastate settlements with the State of Alaska. Our predecessor agency[8] accepted[9] the Intrastate Settlement[10] (the Settlement) because all affected parties supported it; the Commission did not decide that the Settlement produced just and reasonable rates. Since 1986, the TAPS Carriers calculated intrastate rates using the TAPS Settlement Methodology (TSM).[11] The Alaska Public Utilities Commission (APUC) deferred the issue of whether TSM produced just and reasonable rates until a shipper protested the rates. The 1997 Tesoro and Williams protests put that issue before us for the first time in this pipeline's twenty-year history. Under the Alaska Pipeline Act, the Carriers have the burden of proving that the rates calculated and filed using TSM are just and reasonable.

The Carriers did not support their rates with evidence showing that they reflect the costs of providing service. Instead, they assert that because the rates set by TSM are below a benchmark, the filed rates are just and reasonable. The Carriers do

[7]Alaska Const. art. VIII. The Carriers argue that a decrease in intrastate rates will result in an increase in interstate rates and the effect on the State of Alaska will be a net loss. We note that the TSM Settlement provision allowing Carriers to collect their revenue requirement from the combination of interstate and intrastate rates affords Carriers the *option* of raising interstate rates if intrastate rates decrease. The TSM Settlement agreement does not require Carriers to recover costs disallowed as unjust and unreasonable by state regulators from the federal jurisdiction.

[8]The Regulatory Commission of Alaska assumed the duties of the Alaska Public Utilities Commission on July 1, 1999. Ch. 25 SLA 1999.

[9]*Re* Amerada *Hess Pipeline Corp.,* 13 APUC 448 (1993).

[10]BWF-2, *Intrastate Settlement Agreement* (the Settlement). Endnote 1 describes record designations. A review of TAPS litigation history can be found at Endnote 2.

[11]*See* Endnote 3 for a detailed description of TSM.

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not ask us to adopt their benchmark ratemaking methodology to set rates. Instead, they contend that this method demonstrates what rates would have been absent the Settlement and as such provide a good measure of whether the filed rates calculated using TSM are just and reasonable.[12]

To calculate benchmark rates, the Carriers use a rate base that assumes straight-line depreciation from pipeline startup. They use rates of return that include a premium over the average oil pipeline company's cost of capital to compensate investors for substantial early period risks of the TAPS project. They assume that the life of TAPS is no longer than the life predicted at the time of the Settlement. Using these inputs, the Carriers calculate a year-end 1996 rate base to establish 1997-2000 benchmark rates. The Carriers assert because the filed rates are below benchmark rates, the filed rates are reasonable.

To verify the accuracy of the year-end 1996 benchmark rate base, the Carriers calculate the amount of their original investment that they believe they had recovered by the end of 1996. They apply annual revenues for 1977 to 1996 first to operating costs other than depreciation, then to return on rate base and taxes, and finally to depreciation. Their analysis concludes that unrecovered investment as of January 1997 significantly exceeds the year-end 1996 benchmark rate base. The Carriers assert that this verifies that the TSM filed rates are reasonable because it

[12]The Carriers assert that they were directed to file a comparison between TSM rates and those that would have been set by a regulator using traditional ratemaking methodologies. The Carriers misinterpret the language in *Re Amerada Hess Pipeline Corp.*, 13 APUC 448 (1993) and *Re Amerada Hess Pipeline Corp.*, Order P-97-4(79), dated April 10, 2000, to suggest that filed rates should be reviewed as if the past twenty years of rates have not been filed and collected. We disagree. The APUC stated "the filing is subject to the same *standards* and *procedures* to which it would have been subject if the Intrastate Settlement Agreement had not been accepted. *Id.,* at 456 (*emphasis added*). We did not direct that the history of rates filed and collected should be ignored.

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demonstrates that the Carriers have recovered less of their original investment under the Settlement than they would have under the methodology that they assert would have been used had the Settlement not occurred.

The Carriers' urge us to permanently approve the filed 1997-2000 rates and to continue the Settlement's effect. The Carriers also contend that the filed rates calculated using TSM are just and reasonable over the life of the Settlement and that allowing rates to be set using TSM furthers important public policy goals.

The State of Alaska (the State) supports the Carriers' position. The State asserts that public policy concerns also support preserving the Settlement. The State describes its position as (1) ensuring that this case does not affect the validity or enforceability of the Settlement,[13] (2) protecting the State's ability to continue making oil pipeline settlements within the jurisdiction of the Regulatory Commission of Alaska, and (3) protecting its economic interests.

Tesoro disagrees with the Carriers and the State. Tesoro contends that the filed rates for 1997-2000 are not just and reasonable and that AS 42.06 requires us to set just and reasonable rates. Tesoro calculates a year-end 1996 rate base that is much lower than the Carriers'. Tesoro calculates its rate base using the depreciation amounts used to calculate TSM ceiling rates. Tesoro's rate base is lower than the TAPS Carriers' benchmark analysis rate base because Tesoro relies on the depreciation schedule used in TSM which is much more accelerated than the straight-line depreciation the Carriers adopt in their benchmark analysis.

Williams also asserts that the filed rates calculated under TSM are not just and reasonable and that the Carriers' year-end 1996 benchmark rate base is too high.

[13]The Settlement terms require the State to defend against any litigation affecting the validity and enforceability of the Settlement. BWF-2, Section I-3.

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Williams contends that TAPS is nearly fully depreciated but proposes that the basic framework of the Settlement should continue to be used to calculate rates. Williams asks, however, that we change certain elements of the TSM, including adding a management fee.[14] Williams proposes that we require the Carriers to use this adjusted methodology to calculate intrastate rates from 1997 forward.

The Public Advocacy Section (PAS)[15] supports Tesoro's and Williams' arguments. It asserts that the filed rates are not just and reasonable and that we should set new rates using the accelerated depreciation schedule employed in TSM rates, a longer TAPS life, and an adjustment for over collection for dismantling, removal and restoration (DR&R).

During most of the operational history of the TAPS, Carriers have charged the maximum rates allowed by TSM. Carriers filed the cost information used to calculate TAPS rates confidentially under the terms of TSM. Requiring shippers to pay rates based on cost data to which they do not have access is unusual. The policy concerns favoring settlements do not outweigh our statutory obligation to set just and reasonable rates or the policy favoring shipper and public access to the cost data used to calculate those rates.

Alaska statutes[16] require pipeline rates to be just and reasonable. Just and reasonable rates allow pipeline owners an opportunity to recover their investment, a

[14]*See* Endnote 4 for an analysis of Williams' proposed management fee.

[15]The Public Advocacy Section was established in 1999 by the Legislature to operate independently from the Commission and represent the public interest. Ch. 25 SLA 1999. The Commission assigns cases to the Public Advocacy Section when a public interest perspective would add to the full development of the record.

[16]AS 42.06, Pipeline Act.

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return on that investment and their reasonable operational costs.[17] As the Carriers note, the most important element of the cost of service for years 1997-2000 is the amount of the Carriers' investment which they have not yet had an opportunity to recover, their "rate base" at year-end 1996.[18] Because our regulatory predecessors did not decide whether TSM produced just and reasonable rates there is no approved rate base for year-end 1996. To determine the starting point, the year-end 1996 rate base, we must determine the amount of Carrier investment and the amount that they have previously had the opportunity to recover by year-end 1996.

This requires that we use cost information that is outside the 1997-2000 years. We rely on the voluminous historical record to determine an appropriate year-end 1996 rate base. We apply a depreciated original cost (DOC) methodology from the beginning of pipeline operations.[19] We adopt an appropriate capital structure of 49.5 debt/50.5 equity, adopt TSM depreciation charges and set overall annual rates of return ranging from 11 to 15 percent.[20] We generally accept the Carriers' inputs for all other elements of the rate calculation. We find the year-end 1996 rate base is $669 million.[21] We compare our year-end 1996 rate base to the Carriers'. The Carriers calculate a benchmark rate and argue that if filed rates are below the benchmark we should find them just and reasonable. We find that even if the Carriers' benchmark and supporting

[17]*See* Federal *Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).*

[18]"The critical issue in determining the reasonableness of the 1997-2000 rates is the appropriate rate base against which to measure the returns achieved." *Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 40.

[19]*Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n*, 836 P.2d 343, 350 (Alaska, 1992) (affirming rate base computed by taking original cost minus accumulated depreciation).

[20]Exhibit 2, Column g.

[21]*See* Part IV, infra.

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unrecovered investment analyses are logical and legally sufficient to prove that rates are just and reasonable, the Carriers' methodology and choice of inputs to the benchmark analysis and unrecovered investment analyses are unreasonable. As a result, in addition to being insufficient to support filed rates, the benchmark and unrecovered investment analyses fail.

To verify the reasonableness of the $669 million year-end 1996 rate base, we compare TSM revenue requirements for past years with the revenue requirements we calculate using our consistently applied DOC methodology. If TSM's cumulative revenue requirement provided an opportunity to earn less than would have been allowed under an appropriate consistently applied depreciated original cost methodology the Carriers may be entitled to an upward adjustment to the year-end 1996 rate base.[22] However, no adjustment is necessary because we find that by 1997 TSM provided the Carriers an opportunity to earn over $9.9 billion more than the cost of providing service.

We calculate just and reasonable rates for 1997-2000 starting from the $669 million rate base. To calculate the TAPS 1997-2000 revenue requirements, we determine the rate base in each year. We determine an appropriate capital structure, cost of debt, and return on equity for each protested year. The return on equity for this period includes a premium for the early period risk to TAPS. To determine the appropriate depreciation amounts for 1997-2000 rates, we use straight-line depreciation and the now-expected longer life of TAPS. Using these inputs, we calculate the appropriate return on rate base and associated income tax allowance for each year. We use the resulting revenue requirements and the $669 million year-end 1996 rate

[22]*Re* Kenai *Pipe Line Co.,* 12 APUC 425, 438-40, 472 nn.25-26,1992 WL 696192 (Alaska P.U.C., 1992).

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base to compute just and reasonable TAPS rates for 1997, 1998, 1999 and 2000. Those rates are shown below and discussed in Part VI Section F, *infra*.

	GVEA	Petro Star	Valdez
1997	$1.02	$1.55	$1.56
1998	$1.03	$1.62	$1.63
1999	$1.19	$1.88	N/A
2000	$1.25	$1.96	N/A

Finally, we compare these cost-based rates with the TSM filed rates. The Carriers' filed rates for 1997-2000 exceed these rates by an average of 57 percent.[23] Fifty-seven percent above costs is well outside the zone of reasonableness standard that reviewing courts apply. We, therefore, find that the 1997-2000 filed rates are not just and reasonable. We set the above rates[24] that we calculate as the permanent TAPS rates for 1997, 1998, 1999 and 2000. We order the Carriers to calculate and pay appropriate refunds.

II. LEGAL AND POLICY STANDARDS

The threshold issues in these dockets are the appropriate standard of review for filed rates and the method for determining what are "just and reasonable" rates under the Alaska Pipeline Act.

[23]In any given year, the Carriers' filed rates exceed the cost of providing service by 19 to 88 percent. *See* Exhibit 1. Cost based rates, determined in Part.VI Section F, are shown at Schedule 1. The Carriers' average yearly filed rates are shown at Schedule 2. The percentage by which each filed rate exceeds cost-based rates, and the average excess, is calculated at Schedule 3.

[24]AS 42.06.410(a) allows the Commission to fix rates when "after an investigation and hearing, [the commission], finds that a rate demanded, observed, charged, or collected by a pipeline carrier for a service . . . is unjust, unreasonable, unduly discriminatory, or preferential, ..."

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A. Standard of Review for Filed Rates

In 1997, 1998, 1999, and 2000 each Carrier revised its existing tariffs and filed new rates.[25] Under AS 42.06.400(d), "[o]ne who initiates a change in existing tariffs bears the burden of proving the reasonableness of the change." The APUC held that "[e]ach new rate filed by the TAPS Carriers under the Intrastate Settlement Agreement is considered to be a revised tariff filing under AS 42.06.400."[26] The Carriers therefore carry the burden of proving that the filed rates are just and reasonable.[27]

The Settlement does not shift the burden of proof. When the APUC accepted the Settlement, it found that if the Settlement was challenged, the Commission would evaluate the filed rates using the same standards and procedures as if the Settlement had never been accepted.[28] The Carriers therefore carry the burden of proving that the filed rates are just and reasonable.

[25]Amerada Hess (1997) TL50-300, TL52-300 (changed only to Valdez and Petro Star, not North Pole), TL55-300; (1998) TL58-300; (1999) TL63-300, TL64-300. TL66-300, TL68-300; (2000) TL-70-300, TL71-300. ARCO (1997) TL56-301, TL59-301; (1998) TL61-301; (1999) TL 66-301, TL68-301; (2000) TL71-301. BP (1997) TL56-311, TL60-311; (1998) TL61-311; (1999) TL67-311, TL69-311; (2000) TL73-311, TL75-311. Exxon (1997) TL69-304, TL72-304; (1998) TL74-304; (1999) TL80-304, TL81-304; TL83-304; (2000) TL87-304. Unocal (1997) TL52-312, TL55-312; (1998) TL56-312; (1999) TL60-312; (2000) TL64-312. Mobil (1997) TL52-308, TL55-308; (1998) TL58-308; TL63-308; (1999) TL64-308, TL66-308; TL68-308; (2000) TL70-308. Phillips (1997) TL53-310, TL55-310, TL58-310, TL59-310; (1998) TL62-310; (1999) TL67-310, TL69-310, TL71-310, TL73-310; (2000) TL77-310, TL78-310, TL79-310.

[26]*Re Amerada* Hess *Pipeline Corp.*, 13 APUC 448, 456 (1993).

[27]*See* Endnote 5 for a more detailed discussion of burden of proof.

[28]*Re Amerada Hess Pipeline Corp.,* 13 APUC 448 (1993). The APUC stated in its October 29, 1993, order accepting the Settlement "Each new rate . . . is subject to the same standards and procedures to which it would have been subject if the Intrastate Settlement Agreement had not been accepted." *Id.,* at 456. This finding has been reiterated often during the history of this case. The APUC was quite clear at a May 5, 1995, prehearing conference when it stated "The Commission wishes to make it clear that the TAPS Carriers are the ones who need to justify their rates as though TSM had not been approved." Prehearing Conference Transcript at 66 (May 5, 1998).

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B. Just and Reasonable Rates

Whether the filed intrastate 1997-2002 TAPS rates are just and reasonable turns on the following five issues. First, how are just and reasonable rates determined? Second, what is a reasonable methodology for establishing just and reasonable rates? Third, what methodology is appropriate for establishing a year-end 1996 rate base for TAPS? Fourth, how does one determine the reasonable inputs for a DOC methodology? Fifth, does a change in ratemaking methodology in the middle of the operating life of a pipeline result in a return deficiency? We discuss each in turn.

1. *What Are Just and Reasonable Rates?*

Alaska Statute 42.06.370(a) states that "[a]ll rates demanded or received by a pipeline carrier, or by any two or more pipeline carriers jointly, for a service furnished or to be furnished shall be just and reasonable." Courts have developed various criteria for "just and reasonable" rates. Rate orders that fall within a "zone of reasonableness" are neither "less than compensatory" nor "excessive."[29] The "zone of reasonableness" is delineated by striking a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable.[30] The balance is struck by affording the owners of the pipeline a fair opportunity to earn a return commensurate with the risk of their capital investment[31] under tariffs that are fair and nondiscriminatory toward shippers and other members of the relevant public.

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[29]*Farmers* Union *Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984).

[30]*In re* Permian *Basin Area Rate Cases,* 390 U.S. 747, 792, (1968); *In re Trans Alaska Pipeline Rate Cases,* 436 U.S. 631, 653, 98 S.Ct. 2053, (U.S.Tex., 1978).

[31]*See, e.g.* Federal *Power Comm'n v. Hope Natural Gas Co,* 320 U.S. 591, 603, (1944) (*Hope*).

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We have some latitude in determining just and reasonable rates. In arriving at a just and reasonable rate "no single method need be followed."[32] "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. . . . It is not theory but the impact of the rate order which counts."[33]

We have held that "[r]ates that are just and reasonable generate enough revenue to pay the costs actually and prudently incurred by the regulated entity in providing service (including depreciation and taxes) plus a reasonable return to the entity on the original cost of its property in service."[34] If non-cost based factors are to be considered they must be specifically supported.[35] The most useful and reliable starting point for rate regulation is an inquiry into costs.[36] We apply this standard to the filed 1997-2000 TAPS rates.

2. *What Is a Reasonable Methodology for Determining Rates?*

To determine rates, we assess the prudent cost of providing pipeline service.[37] A pipeline's costs include the cost of operation and maintenance and a

[32]*Wisconsin v. Fed. Power Comm'n,* 373 U.S. 294, 309, 48 P.U.R.3d 273, 83 S.Ct. 1266 (U.S.Dist.Col., 1963); *see also, Hope,* 320 U.S. at 602.

[33]*Hope,* 320 U.S. at 602.

[34]*Re Kenai Pipeline Co.,* 12 APUC 425, 433, 1992 WL 696192 (Alaska P.U.C., 1992).

[35]*Farmers Union Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984). Non-cost factors may justify a departure from a rigid cost-based approach. *F.E.R.C. v. Pennzoil Producing Co.,* 439 U.S. 508, 517, 27 P.U.R.4th 473, 99 S.Ct. 765 (U.S.Tex., 1979).

[36]*Farmers Union Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984); *see, e.g., Mobil Oil Corp. v. Federal Power Comm'n*, 417 U.S. 283, 305-06, 316, 5 P.U.R.4th 1, 94 S.Ct. 2328 (U.S.La., 1974); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03 (1944).

[37]*See* BONBRIGHT, JAMES C. ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 237-38 (1988).

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reasonable return of and on capital. The term "rate base" is used to describe the balance of prudently incurred capital investment which the Carriers have not yet had an opportunity to recover in rates and on which Carriers may earn a return. Rate base is a regulatory concept; it is not property.[38]

A pipeline's rate base is increased over time by additional prudent carrier capital expenditures and is decreased by depreciation. Depreciation is included in rates to allow carriers an opportunity to recover their investment principle. As a pipeline recovers its capital investment over time, the rate base declines so that the entire capital investment is recovered by the end of the asset's useful life.

As the Carriers note, "The critical issue in determining the reasonableness of the 1997-2000 rates is the appropriate rate base against which to measure the returns achieved."[39] The Carriers assert that had the TSM not been approved, the rate base at year-end 1996 would be $3.26 billion.[40] The Carriers assert that we should not use the TSM rate base to evaluate filed rates because it reflects compromises made to achieve the Settlement. They further contend that the true value of unrecovered Carrier property is even greater.[41] Williams asserts that the year-end 1996 rate base is $855 million[42] and Tesoro asserts it is $394 million.[43] The PAS suggests that the Carriers' investment has been completely recovered and that the rate base is zero.

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[38]*Cook Inlet* Pipe *Line Co. v. Alaska Public Utilities Comm'n,* 836 P.2d 343, 350 (Alaska 1992).

[39]*Indicated TAPS* Carriers *Initial Post-Hearing Brief*, filed July 16, 2001, at 40.

[40]T-7 20.

[41]T-7 20.

[42]189A-BEW-T, Schedule 5, Line 16. This is the rate base sponsored by Williams as an alternative to the Carriers' benchmark analysis.

[43]JFB 1 Schedule B.

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Throughout the life of the TAPS, tariffs have been calculated using TSM. In accepting TSM, the APUC agreed to allow TAPS rates to be calculated using the methodology in the Settlement until such time as TAPS rates were challenged, but the APUC did not establish or approve a rate base.[44]

We set the year-end 1996 rate base in Part IV, *infra*. To do so we determine the original 1977 rate base and then account for all additions to and subtractions from rate base from 1977 through year-end 1996. In Part V, we verify that the year-end 1996 rate base so established does not deny Carriers a reasonable opportunity to recover their investment.

3. <u>What Methodology Is Appropriate for Establishing Rate Base at Year-End 1996?</u>

In *Cook Inlet,*[45] the Alaska Supreme Court approved a method for determining the appropriate rate base in the middle of a pipeline's operating life. The APUC found that a rate base may be established using a DOC methodology applied as if that methodology had been used from the beginning of pipeline operations.[46]

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[44]*Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993).

[45]*Cook Inlet* Pipe *Line Co. v. Alaska Public Utilities Comm'n,* 836 P.2d 343 (Alaska 1992).

[46]*Re Cook Inlet Pipe Line Company,* 6 APUC 527 (1985); *see generally, Re Kenai Pipe Line* Company, 12 APUC 425, 1992 WL 696192 (Alaska P.U.C., 1992).

The parties do not dispute that this approach is reasonable.[47] The Carriers use a DOC analysis from the beginning of pipeline operations to generate benchmark rates.[48] Tesoro and Williams also use DOC analyses to support their respective cases. We find that a DOC methodology applied from the beginning of pipeline operations should be used in this case to determine rates.

4. <u>How Should Reasonable Inputs for a DOC Methodology Be Determined?</u>

Disputes over appropriate inputs into a methodology are normal in ratemaking. This proceeding is different from a normal rate case because throughout TAPS' history, no agency or court has approved a depreciation schedule or rate of return that has been used to set just and reasonable rates. The parties disagree about

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[47]*Initial Post-Hearing Brief of the Indicated TAPS Carriers,* filed July 16, 2001, at 40-41; *Initial Brief* of *Williams Alaska Pipeline Company LLC*, filed July 16, 2001, at 14; *Tesoro Alaska Company's Initial Posthearing Brief*, filed July 18, 2001, at 26; *Williams Alaska Petroleum Post-hearing* Brief at 18 (if a DOC comparison is to be used TSM's accelerated depreciation schedule should be employed); Public *Advocacy Section Initial Post-Hearing Brief*, filed July 16, 2001, at 11. The parties, however, dispute what the inputs into a DOC methodology should be. The Carriers suggest that a straight-line depreciation should be used. *Initial Post-Hearing Brief of the Indicated TAPS Carriers* at 11-12**;** *Initial Brief of Williams Alaska Pipeline Company* at 16. Tesoro, PAS and Williams contend a consistent DOC methodology from the beginning of pipeline operation should use the TSM depreciation schedule. *Tesoro Alaska Company's Initial Posthearing Brief*, at 28-29; Williams agrees but asserts that the TSM depreciation factors should be used. *Williams Alaska Petroleum Inc.'s Post-hearing Reply Brief*, filed August 1, 2001, at 5, 16-18; *Public Advocacy Section Initial Post-Hearing Brief*, at 9. They argue we should use the depreciation underlying historical filed rates. We agree with Williams, Tesoro and PAS. *See* Parts III, C.2, IV, C.2 and VI B.3.

[48]We did not direct that benchmark rates be calculated. In *Re Amerada Hess Pipeline Corporation*, we instructed the Carriers that, although we believe the most useful and reliable point for rate regulation inquiry is costs, no single method need be followed. *Re Amerada Hess Pipeline Corp.,* Order P-97-4(79) at 8 (April 10, 2000). We reiterated the direction of the APUC in originally allowing TSM rates. The APUC clearly stated TSM rates "would be subject to the same *standards* and *procedures* to which [they] would have been subject if the Intrastate Settlement Agreement had not been accepted." *Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993) (*emphasis added)* and n.28. We explained that determining whether rates are just and reasonable begins with costs. *Re Amerada Hess Pipeline Corp.*, Order P-97-4(79) at 9, 11 (April 10, 2000). Non-cost factors may be considered if specifically justified. *Id.*, at 10.

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the appropriate accumulated depreciation and rates of return that should be used to calculate the TAPS year-end 1996 rate base.

a) A Depreciation Schedule for the TAPS Rate Base Has Never Been Approved

The amount of accumulated depreciation by year-end 1996 affects the rate base and resulting rates. Carriers urge that we calculate the amount of accumulated depreciation at year-end 1996 using a straight-line approach. By doing so, the Carriers conclude that accumulated depreciation is $4.982 billion by year-end 1996.[49]

Past rates for TAPS, however, have been calculated using the TSM accelerated depreciation schedule, not a straight-line depreciation schedule. TSM uses an accelerated depreciation schedule that allows expedited recovery of the Carriers' capital investment.[50] Thus, the depreciation amount charged annually in rates was much larger in the early years of TAPS operation than in later years.

To evaluate the 1997-2000 filed rates, Williams argues that accumulated depreciation through year-end 1996 should reflect the past depreciation *factors*[51] used to set tariffs and collect rates under TSM, and that doing so results in accumulated depreciation of $9.2 billion by year-end 1996.[52] Tesoro[53] and the PAS[54] urge that accumulated depreciation should reflect the actual TSM annual *charges* included in rates, and that the total is $8.1 billion by year-end 1996.

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[49] 143-RGV-C, Workpaper TAPS-RGV WP3.xls, Schedule 5, Line 9.

[50] BWF-4 at 31.

[51] TSM sets depreciation *factors* for each Carrier that are used to calculate annual depreciation charges.

[52] 189A-BEW-T, Schedule 2, Line 2.

[53] JFB 1 Schedule B.

[54] RAF-4, Schedule 1, Column 3.

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Depreciation schedules are established for a variety of purposes. The Federal Energy Regulatory Commission (FERC) generally requires Carriers to use straight-line depreciation when filing FERC Form 6.[55] The Form 6 filings allow FERC to compare pipeline costs.[56] For tax purposes, entities often choose accelerated depreciation.

Regulatory bodies establish a depreciation schedule for ratemaking. The depreciation schedule determines the amount of annual depreciation allowed in the revenue requirement, thereby providing carriers an opportunity to recover their investment over time. In this case, because a depreciation schedule for TAPS has never been approved, we determine both the historical depreciation charges through year-end 1996 and the current depreciation charges for 1997-2000.

The Settlement sets a depreciation schedule. By accepting the Settlement for post-July 11, 1986 rates, the Commission did not find that the TSM depreciation schedule produced just and reasonable rates.[57] The parties contest whether the annual TSM depreciation schedule gave the Carriers adequate opportunity to recover their investment.

Carriers contend that if we adopt TSM depreciation[58] to calculate past recovery of investment they will be deprived of the opportunity to recover their investment.[59] To set cost-based rates we must use a depreciation schedule that provides Carriers with the opportunity to recover their investment from 1997 through

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[55]Tr. 3147 (RGV); Tr. 4865 (KAW).

[56]*See* Tr. 2386-87 (LPS);Tr. 2411-12 (LPS).

[57]*Re Amerada Hess*, 13 APUC 448 (1993).

[58]*See* Part III,C.2. for an analysis of the Carriers' choice of straight-line depreciation.

[59]T-6 (WBT) 26.

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2000, yet does not require shippers to pay costs twice.[60] We determine the appropriate accumulated depreciation and the future annual deprecation schedule in Part IV Section C.2 and Part VI Section B.3, *infra*.

b) The Rate of Return Should Be Based on the Return Required by a Stand-alone Pipeline

The rate of return compensates investors for the use of their capital. As with depreciation, we determine not just rate of return for the years with disputed rates but also rate of return for previous years. The appropriate rate of return determines the size of allowance for funds used during construction (AFUDC), an important component of rate base. Regulators use AFUDC to compensate pipeline owners for construction costs. The capital costs incurred during construction are not includable in the rate base until those costs can be linked to an asset that is used and useful in providing service. Carriers account for construction costs and add the cost of financing the capital investment during construction. This total AFUDC is added to the rate base when the asset goes into service.

Because the financing costs are included in AFUDC, a larger rate of return results in a larger AFUDC balance and a smaller rate of return results in a smaller AFUDC balance. Carriers suggest that starting AFUDC balances in 1977 were $2.562 billion;[61] Williams suggests that starting AFUDC balances in 1977 were $2.006 billion;[62] Tesoro suggests that AFUDC in 1977 was $1.246 billion.[63]

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[60] *Re Cook* Inlet *Pipe Line Co.*, 2001 WL 1850233 (RCA Oct. 29, 2001).

[61] 143-RGV-C. Workpaper TAPS RGV-WP3.xls, Schedule 4, ll. 6, 9.

[62] 189A-BEW-T Workpaper BEW_R_RGV WP! DR 22RE.xls, Schedule 4 ll. 7, 11.

[63] 225-JFB-T, Workpaper 2 JFB-1 page 1 l. 4.

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In this case, determining the appropriate rate of return is complicated in two ways. First, it is highly unusual to determine an appropriate rate of return for years before rates are at issue. The rate of return is generally determined prospectively. The compensation that investors require for the risks to which they expose their capital is based on investors' prospective reading of those risks. In this case, the rate of return in distant *past* years must be determined from the vantage point of investors' prospective expectations at that time. The parties approach this task by using their analyses of 1997-2000 rates of return to backcast[64] the cost of capital in prior years.

Second, to determine rate of return we must consider the business and financial structure of the TAPS for ratemaking purposes. We must decide whether to treat the TAPS as a separate entity or as an amalgam of its owners. TAPS is still owned by seven individual pipeline companies; six are subsidiaries of North Slope producers. The TAPS does not exist as a separate entity in which investors actually can invest. Instead, each share of TAPS is generally owned by producer parent companies. The parent companies are generally large integrated petroleum companies. The risks faced by integrated petroleum companies do not reflect the risks for which a pipeline company would need to be compensated.

The parties agree that the rate of return allowed in rates should be based on the business risk of TAPS.[65] As one witness explained:

> [W]e're trying to determine what business risks are associated with that stand-alone enterprise so that we can compensate investors and ask rate payers to pay a rate of return which is commensurate with that risk and not other risks.[66]

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[64]The word "backcast" is the opposite of "forecast"; it is used to describe the method of extrapolating results from the current period to earlier periods.

[65]T-3 (WBT), p. 60; Tr. 2743 (WBT); FJH-T (E-2) at 18; WBT-59.

[66]Tr. 2937 (WBT).

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This is consistent with controlling legal authority on TAPS. In response to an appeal from Alaska Pipeline Commission's (APC) 1983 decision setting the first tariff for intrastate transportation of oil on the TAPS, the Alaska superior court reversed a contrary APC finding and described the TAPS as follows:

> TAPS is, in fact, a single pipeline and not eight individual pipelines of varying capacities. There is no basis for taking the capitalization of eight oil companies who are the owners or parent companies of the owners and imputing their individual capitalization to TAPS. The pipeline should have been considered to be an entity and capitalization, costs, rates of return on both debt and equity capital, and other financial information should have been imputed to it.[67]

Although the superior court's decision was vacated by the Alaska Supreme Court[68] because the parties settled their appeal, the Alaska superior court's description of the TAPS is still relevant. It suggests that we should view the TAPS as a single, stand-alone enterprise.

A "stand-alone" enterprise is one that can attract capital on its own. It provides a good lens for determining what investors would require for a return in light of TAPS' business risks. We prefer the stand-alone model because it is more likely to reflect the reasonable costs of capital. We do not use the actual cost of capital used to finance the TAPS construction because it is complicated by financial arrangements between parents and subsidiaries that make it difficult to determine the prudent cost of capital for a stand-alone TAPS. For example, if a carrier were to choose an unwise method of financing, its costs would be unreasonably high. As regulators we do not

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[67]*State of* Alaska *v. Alaska Public Utilities Comm'n*, 3AN 80-7163 CI (Alaska Super.) Nov. 28, 1983.

[68]*Amerada Hess Pipeline Corp. v. Alaska Public Utilities Comm'n*, No. S-195, slip op. (Alaska Nov. 20, 1985).

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allow recovery of imprudent costs.[69] Accordingly, we determine rate of return based on the cost of capital of a "stand alone" TAPS.

The return demanded by a stand-alone TAPS consists of the weighted average of the cost of debt and the return on equity. The relative weights are determined by the relative amounts of capital used to finance debt and equity. The relative amounts of debt and equity are known as the capital structure.

To determine what portion of return compensates for the cost of debt and what portion provides for return on equity, we rely either on the regulated entity's actual capital structure or choose a hypothetical capital structure if the actual capital structure is inappropriate. Consistent with the need to determine rate of return based on a stand-alone model, we determine the capital structure for TAPS based on a stand-alone model.[70]

5. Does a Change in Ratemaking Methodology in the Middle of the Operating Life of the Pipeline Result in a Return Deficiency?

Because we are applying a ratemaking methodology in the middle of the operating life of TAPS that is different than TSM, we must confirm that the year-end 1996 rate base so calculated is reasonable and will not deprive the Carriers of the opportunity to earn a reasonable return. The Carriers,[71] perform an unrecovered investment analysis to verify that their proposed rate bases are reasonable. Tesoro and Williams perform an unrecovered investment analysis to show that the Carriers' benchmark rate base is unreasonable and that investment has been mostly recovered.

[69] *Re Cook Inlet Pipe Line* Company, 2001 WL 1850233 (RCA Oct. 29, 2001).

[70] Using a stand-alone model is consistent with the Alaska Superior Court holding in *State of Alaska v.* Alaska *Public Utilities Comm'n*, 3AN 80-7163 CI, (the APC erred in setting rates based on a model that reflects the capitalization and capital costs of the multiple owners of TAPS).

[71] RGV-15.

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We analyze and reject the unrecovered investment analyses because they are unreliable. In some situations they may also violate the rule against retroactive ratemaking.[72]

Instead, we use the annual comparative revenue requirement analysis described in *Kenai*[73] to confirm that the year-end 1996 DOC rate base calculated in the middle of the operating life of the pipeline is reasonable. In *Kenai*, the APUC held that a new rate base established midstream may be adjusted if a regulatorily enforced return deficiency results from a switch in ratemaking methodology. The APUC explained

> The Commission does not believe that it is legally or constitutionally required to recognize such a return deficiency. However, if one were demonstrated, then the Commission would consider whether, in fairness, an adjustment ought to be made for it.[74]

Neither this Commission, nor our predecessor agencies, the APUC and the APC, have ordered a rate base adjustment for this reason. However, if the Carriers are denied an opportunity to recover and earn a reasonable return on their investment due to a switch in ratemaking methodology an adjustment may be appropriate.[75]

A regulatory agency must provide an opportunity to earn a return;[76] but, it does not guarantee a return. In this case, the Carriers negotiated a future opportunity to earn a return when they entered into the Settlement. They assumed the risk that at some time during the life of the Intrastate TAPS Settlement Agreement a shipper might

[72]*See* Endnote 6 for a discussion of retroactive ratemaking.

[73]*Re Kenai Pipe Line Co.,* 12 APUC 425, 1992 WL 696192 (Alaska P.U.C., 1992) (*Kenai).*

[74]*Id.*, at 439.

[75]*Id.,* at 438. Similarly, if through past rates carriers have enjoyed excessive opportunity to recover costs, a downward adjustment to rate base may be appropriate. *See* T-10 (WBT), 84:3-14; *Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 18.

[76]*Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 (RCA Oct. 29, 2001).

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protest and a commission would determine that rates filed pursuant to the Settlement are not just and reasonable. The Carriers were never guaranteed their *future* negotiated returns.[77]

The year-end 1996 rate base should provide an opportunity to earn a reasonable return but need not guarantee the future negotiated return allowed in the Settlement. We, therefore, compare TSM's annual revenue requirements with cost-based DOC revenue requirements to ensure that the Carriers will not be denied an opportunity to recover their costs. By doing so we verify that the rate base we calculate for year-end 1996 does not result in the Carriers losing their opportunity to earn a return.

III. THE CARRIERS FAIL TO SHOW THAT FILED RATES ARE JUST AND REASONABLE

In a typical rate case, the regulated entity proposes a rate base and we determine whether the proposed rate base is correct for ratemaking purposes. We also review the other elements of the proposed ratemaking methodology to determine whether they are reasonable.

The Carriers present an unconventional case. They compute two different rate bases, one in the benchmark analysis and one in their unrecovered investment analysis. They do not support either as the rate base that we should adopt for ratemaking purposes.[78] Further, they do not propose that the labeled components of

[77]When the APUC considered the Settlement in 1987, it indicated that when rates filed pursuant to the Settlement are challenged, the Commission will determine whether those rates are just and reasonable and if not, will calculate just and reasonable rates. *See Re Amerada Hess Pipeline Corp.*, 8 APUC 168, 169 (1987). Therefore, the Carriers were on notice that the APUC acceptance of the Settlement did not guarantee the return contemplated in the Settlement.

[78]Tr.1726-27 (ABJ); Tr. 1846 (ABJ); Tr. 3324 (RGV).

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"rate base" in the TSM model be adopted as a DOC rate base for TAPS. They claim that they cannot file a typical rate case because the filed rates are not determined by a conventional rate base rate of return methodology. They assert that the building blocks of the TSM filed rates cannot be converted directly into standard ratemaking elements.[79]

Instead, the Carriers make three arguments in support of filed rates. In Section A below, we address the Carriers' argument that over the life of the line TSM rates are just and reasonable and therefore are just and reasonable for 1997 through 2000. In Section B we address the argument that the filed rates are just and reasonable based on public policy grounds.[80] In Section C we address the argument that if filed rates are below benchmark rates then filed rates are just and reasonable.

A. The Carriers Fail to Prove That TSM Rates Are Just and Reasonable Over the Life of the Line

The Carriers suggest we should determine whether the filed rates are just and reasonable by calculating an internal rate of return (IRR) on their investment in TAPS and comparing that IRR to the average required rate of return over the life of the line.[81] If the IRR does not exceed the required rate of return on capital at the time of settlement, the Carriers assert that the rates in all years must be just and reasonable.

In *Re Amerada Hess Pipeline Corporation*, Order P-97-4(79), dated April 10, 2000, we assumed for the purposes of argument that the Carriers had shown that TSM rates were just and reasonable over the life of the line. We found that, even if the Carriers proved that rates were just and reasonable over the life of the line, that proof is not sufficient under AS 42.06 to establish that rates in any particular year were just and

[79]*See* T-5 (ABJ) 24.

[80]The State also asserts that filed rates are just and reasonable based on public policy grounds. *State of Alaska's Prehearing Brief*, filed April 5, 2001, at 7; *State of Alaska's Initial Post-hearing Brief* at 2, filed July 16, 2001.

[81]T-1 (ABJ) 15.

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reasonable. We instructed the Carriers to submit proof that each of the filed rates at issue in this proceeding was just and reasonable for the year in which it was filed.[82] The Carriers subsequently submitted evidence relating to individual years, as instructed, but continue to assert that the filed rates are just and reasonable because the IRR they calculate under TSM is no higher than the rate of return required at the time of the Settlement.

The Carriers calculate IRRs for each of three different sets of data, performing two separate IRRs for each set of data.[83] The IRR on a project varies depending upon whether and to what extent the investor can utilize tax benefits generated by interest deductions associated with the investment. The Carriers calculate one IRR on each set of data assuming no tax benefit from interest deductions and another assuming full tax benefit.[84] All three sets of data yield IRRs that are in the low range or are lower than the required overall rates of return recommended by the Carriers' rate of return witness.[85]

The use of IRRs in a ratemaking context is novel. Businesses use IRRs to analyze current investments or investment opportunities. To calculate an IRR, a business must project expected future cash flows of the project being analyzed. An IRR requires speculative assumptions about future data. Large differences in the amount of future cash flows make little difference in an IRR because future cash flow amounts

[82]*Re Amerada Hess Pipeline Corp.*, Order P-97-4(79), dated April 10, 2000 (Order 79) at 11, 15.

[83]*See* ABJ-3. The three sets of data reflect different assumptions about TAPS throughput.

[84]T-1(ABJ) 19.

[85]T-1 (ABJ) 21.

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may be heavily discounted. Mathematically, the further into the future a difference in cash flow occurs, the less impact that difference has on the IRR.

We find the RR analysis is an unreliable tool in this case for determining if rates are just and reasonable. The Carriers' IRR analysis is based on speculative assumptions about future throughput, operating expenses and capital costs. Even if an IRR analysis was appropriate, when we compare the overall rates of return found reasonable in this order[86] to the Carriers' IRRs, the Carriers' IRRs on all three sets of data are significantly in excess of appropriate rate of return during the settlement period.[87]

B. The Carriers' and the State's Public Policy Arguments Are Insufficient to Approve Filed Rates

The Carriers and the State make a public policy argument that the Settlement is in the best long-term interests of Alaska. They argue that TSM provides a declining tariff profile, rate stability and avoids expensive, repetitive rate litigation. Further, the State claims that TSM's net carryover provision reduces Carrier incentive to "game" the normal rate-setting process, i.e., it reduces carrier incentive to inflate test-year costs above those likely to prevail in future years. TSM also allows the State to annually review and audit tariffs before rates are filed. Finally, the State suggests that the Settlement encourages development on the State's oil-bearing lands, and positively

[86] *See* Exhibit 2 for summary of appropriate rates of return for 1977-1996; these findings are made in Part IV Section B.

[87] The Carriers' numerical case regarding appropriate rates of return for 1968-1998 did not change between their first and second prefiled cases. *See* T-3 (WBT) and T-6 (WBT).

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affects State revenues. The State concludes that these public policy benefits are so great that we should not invalidate or modify the Settlement.[88] The Carriers concur.[89]

The Settlement does not set rates.[90] Instead, the Settlement requires the Carriers to file rates at or below a ceiling. It also prevents the State from protesting any rate so filed.[91] The terms of the Settlement do not provide that the Settlement is voided if we set just and reasonable rates below the TSM maximum ceiling rates. The results in this case therefore do not invalidate or modify the Settlement.[92] AS 42.06 requires that we consider whether filed rates are just and reasonable The settling parties nonetheless may choose to modify the terms of the Settlement as the result of this order in this case, but our order regarding whether the 1997-2000 filed rates are just and reasonable does not require them to do so.

The State and the Carriers assert that if we find 1997-2000 filed rates do not satisfy AS 42.06 we will create a chilling effect on future settlements. We disagree. The parties to the Settlement have been on notice that the APUC conditioned its acceptance of the Settlement on allowing nonsettling parties to protest rates in the future. The APUC cautioned that rates set by TSM were "subject to the same standards and procedures to which [rates] would have been subject if the Intrastate Settlement Agreement had not been accepted."[93] We must decide whether filed rates are just and

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[88]*State of Alaska's Prehearing Brief* at 7, filed April 5, 2001.

[89]*TAPS Carriers' Covering Brief*, October 8, 1998, at 2, 12, 13.

[90]*State of Alaska's Initial Post-hearing Brief* at 2, filed July 16, 2001.

[91]BWF-2, Sections I-3 and I-4(c); *State of Alaska's Initial Post-hearing Brief* at 3.

[92]Professor Jaffe testified that a commission ordered rate reduction based on a finding that TSM rates exceeded cost-based rates would not be inconsistent with the Settlement. Tr. 1643-1644 (ABJ).

[93]*Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993).

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reasonable when a third party challenges rates.[94] The Carriers and the State therefore cannot now and could not at the time of settlement reasonably expect that rates calculated under the Settlement will always be accepted without review.

We recognize that when parties enter into rate settlements they have hopes of future revenue opportunities and tariff limitations. However, the role of regulating agencies is not to guarantee any particular revenue opportunity or rate. In the regulatory arena, settlements are always at some risk because at any time they may be subject to a test of whether they satisfy AS 42.06. If we are unwilling to review rates when challenged, we abdicate our responsibility under the Alaska Pipeline Act to ensure that rates are just and reasonable.[95] In the context of rate regulation, settlements are always subject to future challenge by third parties. We therefore find that our review of rates in this case does not produce any special chilling effect.

The State and Carriers also assert that the Settlement provides a declining tariff profile, rate stability, and avoids expensive, repetitive rate litigation. We agree that tariffs should be appropriate and the cost of maintaining such rates

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[94]AS 42.06.

[95]Settlements regarding future regulated rates are different from settlements that involve past unregulated behavior. In the regulation arena, future intrastate rates are subject to AS 42.06. Therefore, settling parties in the regulatory arena are always at risk that settlement-produced rates can be challenged and found to violate AS 42.06.

Settlements, however, can be drafted to provide some certainty regarding future rates. For example, in approving the Cook Inlet Pipe Line Company settlement, we required as a condition of approval that the parties stipulate that the depreciation component of the settlement would be "used for ratemaking purposes for [Cook Inlet Pipe Line Company], so long as [it] continues to be regulated under a depreciated original cost methodology." Doing so "allows us to keep track of investment recovery and removes a number of potentially troublesome issues from a future rate case, in the unlikely event one should occur." *Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 at 3 (RCA Oct. 29, 2001). This type of condition for approving a settlement may constrain the negotiable elements of a settlement, but it also provides certainty about the reliability of certain settlement elements in the event of a challenge that filed rates do not satisfy AS 42.06.

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reasonable. Although settlement can accomplish these goals, the 1997-2000 intrastate rates produced by the Settlement do not. Rate case costs are a necessary part of regulation and are appropriate to confirm that rates are just and reasonable. This case resulted in extraordinary expenses because no regulatory agency has determined the appropriate methodology and inputs for calculating rates for this pipeline. The result of this order should be stable rates and lower litigation expenses in the future. We agree with Tesoro witness Williams who testified:

> In my view, when a regulatory agency, this Commission or any commission, clearly delineates what its standards are and what it's procedures are, and what its approach is for developing rates, once that occurs, the parties understand that's -- those are the criteria, those are the approach, that generally greatly reduces the amount of litigation. It's only uncertainty that encourages litigation.[96]

Finally, the State and Carriers allege that if we find filed intrastate rates not just and reasonable and order intrastate rates that differ from interstate rates, then state royalties, tax revenues, bidding, exploration, and development of State oil-bearing lands will be negatively affected.[97] We find that these contentions are not adequately supported.

The ultimate effect of intrastate TAPS tariffs on the State's revenue position is not as transparent as the State and the Carriers indicate. We agree with PAS witness Fineberg who testified:

> The fact that the State gave up any potential State revenue gains from reduced TAPS tariffs in intrastate commerce in the settlement that established TSM does not diminish or dismiss this Commission's responsibility to protect shippers within its jurisdiction by assuring just and reasonable intra-state tariffs.[98]

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[96]Tr. 4915 (KAW).

[97]*State of Alaska's Initial Post-hearing Brief,* July 16, 2001, at 4-6, 11; *State of Alaska's Post Hearing Reply* Brief, 22-25, 31-32; *TAPS Carriers' Covering Brief,* October 8, 1998 at 2, 12, 13.

[98]P-1 (RAF) 8.

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We must consider both the immediate and long-term consequences for setting intrastate rates that are based on costs and may differ from interstate rates.[99] We must strike a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable.[100]

The Interstate TAPS Settlement Agreement has a net crediting provision regarding intrastate TAPS revenues. If intrastate revenues decrease, then the TSM interstate revenue requirement *may* increase.[101] The Carriers may choose to take advantage of this crediting provision in setting interstate rates. Given the terms of the State's royalty agreements with producers, the value of North Slope oil and hence State royalty payments will decline with an increase in interstate TAPS tariffs.[102] The PAS suggests that revenues to the State from 1997 through 2000 would decrease by no more than $10 million per year.[103]

However, although the Carriers may apply revenue "shortfalls" from intrastate to interstate tariffs, nothing in the Interstate Settlement Agreement requires them to do so. If the Carriers take advantage of the Settlement's crediting provision, future interstate tariffs for the same transportation service will rise above the cost-based intrastate rates that we determine in this order to be just and reasonable. Although the

[99]In addition to the public policy arguments the Carriers assert that an interstate shipper could file an Interstate Commerce Act Section 13(4) claim with the Federal Energy Regulatory Commission if interstate rates to Valdez, Alaska are different than intrastate rates to the same destination. The Alaska Supreme Court has already rejected this contention. *Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n,* 836 P.2d 343, 351-53 (Alaska, 1992) *citing Simpson v. Shepard*, 230 U.S. 352, 417, 33 S.Ct. 729, 748 (1913). For a more complete discussion see Endnote 7.

[100]*In re Permian Basin Area Rate Cases,* 390 U.S. 747, 797 (1968).

[101]Tr. 3855 (WDVD); *State of Alaska's Initial Post-hearing Brief* at 11, filed July 16, 2001; 258-RAF-S.

[102] S-1 (WDVD) 3-4.

[103]Tr. 5623 (RAF).

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Carriers certainly have incentive to raise rates, they also have an incentive to treat the State and intrastate shippers fairly.

From a long-term perspective, the effect on State revenues of setting cost-based intrastate rates is likely to be beneficial. First, in light of this order, an independent interstate shipper may protest interstate TAPS rates. If such a protest were successful, the State's royalty and severance tax position will improve. Second, even if a protest of interstate rates were not made or was not successful, lower intrastate tariffs provide increased incentives for exploration[104] and in-state downstream processing. Were this to occur the State's revenue and resource development position would improve.[105]

The State nonetheless asserts that establishing intrastate rates that are different from interstate rates will have a detrimental effect on bidding, exploration and development of State oil-bearing lands. That assertion is not supported by the record. As noted above, near-term royalties will be lost to the State only if Carriers take advantage of the crediting provision. If the Carriers do not take advantage of the crediting provision, the lower royalties to the State would then provide an exploration incentive and an economic incentive for bidding, exploration and development of oil-bearing lands. Therefore, the State's argument that our finding intrastate rates different from interstate rates is harmful to the State is not persuasive.

The United States Supreme Court has held that a regulatory commission is "obliged at each step of its regulating process to assess the requirements of broad public interests." [106] Non-cost factors may legitimize a departure from a rigid cost-based

[104]Tr. 3881 (WDVD).

[105]Tr. 5598 (RAF).

[106]*In re Permian Basin Area Rate Cases*. 390 U.S. 747, 790 (1968).

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approach.[107] The mere invocation of them however is not sufficient.[108] Each non-cost factor must be made to justify the resulting rate for the specific years in question.[109]

Further, the United States Supreme Court decision in *F.E.R.C. v. Pennzoil Producing Company*[110] held that rates must lie within a zone of reasonableness. That zone is found by striking a balance between the financial interests of the regulated company and the relevant interests both existing and foreseeable.[111] As shown in Exhibit 1, Schedule 3 the 1997-2000 filed rates exceed cost-based rates by an average of 57 percent, with the excess ranging from 19 to 88 percent. This range is in such excess of cost-based rates that the rates are driven outside the zone of reasonableness even when considering non-cost factors.

In *Farmers Union* the D.C. Circuit required a reasoned explanation of non-cost factors to justify the resulting rates.[112] As Tesoro has noted, in the past commissions have made only small adjustments to cost-based rates to accommodate non-cost based factors and never in petroleum or petroleum product pipelines.[113] Although the Carriers and State have provided some rationale for including non-cost factors, they have failed to provide sufficient justification for rates exceeding costs by 19 to 88 percent. These percentages are outside the zone of reasonable and fail the basic

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[107] 439 U.S. 508, 517, 27 P.U.R.4th 473, 99 S.Ct. 765 (U.S.Tex., 1979); *Mobil Oil Corp. v. Federal Power Comm'n*, 417 U.S. 283, 305-06, 316, 5 P.U.R.4th 1, 94 S.Ct. 2328 (U.S.La., 1974).

[108] *Id.*

[109] *See Farmers Union Cent. Exchange, Inc. v. F.E.R.C.,* 734 F.2d 1486, 1502-03, 1530 (D.C. Cir., 1984).

[110] *F.E.R.C. v. Pennzoil Producing Co.,* 439 U.S. 508, 517, 27 P.U.R.4th 473, 99 S.Ct. 765 (U.S.Tex., 1979); *In re Permian Basin Area Rate Cases,* 390 U.S. at 797.

[111] *Re Permian Basin,* 390 U.S. at 797.

[112] *Farmers Union Cent. Exchange, Inc. v. F.E.R.C.,* 734 F.2d 1486, 1502 (D.C. Cir., 1984).

[113] *Tesoro Alaska Company's Initial Posthearing Brief* at 34-36.

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test of *Farmers Union*, which does not permit profits that are "too huge to be reconcilable with the legislative command" to produce just and reasonable rates.[114]

C. The Carriers' Benchmark Analysis Fails to Satisfy the Burden of Proof for Two Reasons

We turn to the Carriers' final argument that filed rates must be just and reasonable because they are lower then benchmark rates calculated using a DOC methodology consistently applied from the beginning of pipeline operations. That analysis fails to satisfy AS 42.06. The Carriers' benchmark analysis is neither reasonable nor legally sufficient, and even if it were, the factual inputs the Carriers choose for the benchmark rate base are untenable. Moreover, the unrecovered investment analysis presented as a check on the reasonableness of the benchmark rate base is unreliable.

1. A Benchmark Analysis Is Neither Reasonable Nor Legally Sufficient

The Carriers' benchmark analysis presumes that rates falling below a specified benchmark are necessarily just and reasonable. AS 42.06.370 requires that we find that rates are just and reasonable, not simply that they are below a just and reasonable threshold. The proposition that if filed rates are below a benchmark they are necessarily just and reasonable may not always be true. The goal of regulation is to balance the needs of both carrier and shipper. To do so requires that we establish, to the best of our ability, based on the record before us, rates that achieve that balance. If we endorse rates because they fall below a ceiling of reasonable rates, then carriers may not receive the return that they are due. Rates would then be confiscatory and not just and reasonable.

[114]*Farmer's Union*, 734 F.2d 1486, 1502-1503, quoting *Pub. Serv. Comm'n v. F.E.R.C.*, 589 F.2d 542, 550 (D.C. Cir., 1978).

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The D.C. Circuit Court of Appeals explained to the FERC quite clearly that approving rates that fall below a cap is not an acceptable way to set just and reasonable rates. The D.C. Court stated that setting a ceiling in that case only served as a cap on egregious price exploitation by regulated pipelines; it did not properly set just and reasonable rates.[115]

This same rationale applies to the Carriers' use of a benchmark to determine whether the filed rates in this case are just and reasonable. When faced with a protest, we are obligated under AS 42.06.370 to determine whether filed rates are just and reasonable, not just whether they fall below a benchmark.

2. *__The Carriers' Benchmark and Unrecovered Investment Analyses Are Unreasonable Because the Depreciation Schedule Used Is Unreasonable__*

The TAPS Carriers assert that we should use a benchmark to assess the justness and reasonableness of 1997-2000 rates. The Carriers calculate benchmark rates and the year-end 1996 rate base by applying a straight-line depreciation schedule from the beginning of TAPS operations.[116] They suggest that both economic reality[117] and Commission precedent[118] require adopting a straight-line schedule. Williams,[119] Tesoro,[120] and the PAS[121] assert instead that the TSM's depreciation schedule or TSM

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[115]*Farmers Union Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984).

[116]*Post-Hearing Reply Brief of the Indicated Taps Carriers* at 13.

[117]*See* T-9 (ABJ) 22; *Initial Post-hearing Brief of the Indicated TAPS Carriers*, at 4-5, 14, 40-41.

[118]*Initial Post-hearing Brief of the Indicated TAPS Carriers,* at 9.

[119]189-A-BEW-T. *See also Williams Alaska Petroleum Inc.'s Post-Hearing Initial Brief* at 11.

[120]*Tesoro Alaska Company's Initial Posthearing Brief* at 28-29.

[121]*Public Advocacy Section Initial Post-hearing Brief* at 9

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depreciation factors should be used to establish the rate base for 1997-2000. They cite both economic arguments [122] and legal precedent[123] to support this position.

The correct depreciation schedule is critical for deciding whether 1997-2000 TAPS tariffs are just and reasonable. The Carriers' proposed straight-line schedule applied from 1977-1996 suggests that roughly 46 percent of the Carriers' initial investment in TAPS remains unrecovered.[124] The TSM depreciation schedule, applied from 1977-1996, suggests that roughly 3 percent of the Carriers' initial investment remains to be recovered.[125] These different depreciation schedules imply vast differences in remaining unrecovered investment, and thus in rate base. If the Carriers' choice of all other inputs into the benchmark DOC were appropriate for 1997-2000 but TSM depreciation charges are used, then filed rates fail the Carriers' benchmark test.[126] Conversely if protestants' choices of all other inputs into their respective benchmark DOCs were appropriate for 1997-2000, but straight-line depreciation charges are used, then the filed rates may pass the Carriers' benchmark

[122]BEW-T (W-3) 12; JFB-T, 45; *see Tesoro Alaska Company's Initial Posthearing Brief* at 19.

[123]Tr. 4910 (KAW).

[124]This figure assumes that the TAPS has an economic life of 34.5 years.

[125]Figure is derived from TSM depreciation factors contained in 29 ABJ-W. 29 ABJ-W Exhibit Alaska __(TOH-1) shows that the TSM depreciation schedule would result in over 90 percent recovery of the Carriers' initial TAPS investment by 1990.

[126]*See* Exhibit 3, Schedule 1.

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test.[127] Thus, the choice of depreciation schedule is critical to the evaluation of filed rates.[128]

We must use a depreciation schedule that when applied from 1977 through 1996 both provides the Carriers with an opportunity to recover their capital investment and also does not force shippers to pay for that investment twice.[129] We find that the depreciation schedule that has actually been used, i.e., the TSM depreciation schedule -- best meets these twin objectives.[130] Below, we address economic and then regulatory arguments about which depreciation schedule is appropriate for determining year-end 1996 rate base.

a) <u>The Carriers' Economic Arguments For Using Straight-line Depreciation Are Unpersuasive</u>

As the Carriers note, a depreciation schedule "can be viewed as 'neutral' in terms of [its] impact on rates overall. This is because [it] affect[s] the timing and not the ultimate value of the rates."[131] Nonetheless, the Carriers assert that using TSM

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[127]T-9 (ABJ) 16; T-10 (WBT) 6-7.

[128]The appropriate choice of depreciation schedule, however, is not necessarily determinative of whether filed rates are just and reasonable. A comparative revenue requirement analysis as directed by *Kenai* shows that even if we assume straight-line depreciation the Carriers have had ample opportunity to recover their investment. *Re Kenai Pipe Line Co.*, 12 APUC 425, 440, 1992 WL 696192 (Alaska P.U.C., 1992). *See* n.550 and Exhibit 4, Schedule 1, lines 9-10 for 1996.

[129]*Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 (RCA Oct. 29, 2001). We are restricted to looking only at the opportunity that the Carriers have had to recover, not what they actually recovered. To look at what they actually recovered may violate the rule against retroactive ratemaking. *See* Endnote 6. We note, however, that in this case because of TSM's true-up mechanism the Carriers' have actually recovered what they had the opportunity to recover. *See* Endnote 3 for an explanation of TSM's true-up mechanism.

[130]We find that the 1997-2000 filed rates are not just and reasonable even when measured against benchmark rates calculated using all of the Carriers' inputs except straight-line depreciation. *See* Exhibit 3, Schedule 1.

[131]T-9 (ABJ) 32.

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depreciation to establish rate base would deny them an opportunity to recover their costs. The Carriers' argument turns on whether TSM's revenue requirement has historically been insufficient to cover TSM's stated amounts of "depreciation" while also giving the Carriers a fair opportunity to earn their contemporaneous required return.[132] If TSM generated inadequate allowed rates of return, then TSM's depreciation schedule should arguably not be used in isolation to determine year-end 1996 rate base. Doing so might deprive the Carriers of the opportunity to recover their investment. However, if the revenue requirement under TSM provided the Carriers with a fair opportunity to contemporaneously recover their investment according to the TSM depreciation schedule and earn an appropriate return, then it would be inappropriate to use anything other than the TSM's depreciation schedule to determine rate base for 1997-2000 rates. Doing otherwise could require shippers to pay for the same costs twice.

When the Settlement Agreement was approved, the Carriers represented that depreciation in TSM was investment recovery. In their 1987 brief to the APUC in support of the Settlement Agreement, the Carriers argued that:

> The so-called factored unit-of-throughput *depreciation* profile is an integral element of the overall settlement arrangement. This mechanism permits the TAPS Carriers to *recover* a major portion of their capital investment in the early years of the pipeline's life, when there is clearly sufficient throughput to support *recovery* of the *depreciation charges*.[133]

Other parties to the Settlement Agreement also suggested that the "depreciation" term within TSM was intended for investment recovery. The United States Department of Justice and the State, in support of the Settlement, explained that:

> Four of the eight elements of the Total Revenue Requirement are associated with the *recovery* of a TAPS Carrier's costs: Operating Expenses; the Dismantling, Removal, and Restoration (DR&R) Allowance; *Depreciation*; and the Income Tax Allowance. Two elements, After-Tax

[132]T-6 (WBT) 26.

[133]7-ABJ-E *(emphasis added)*.

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Margin and Recovery of Deferred Return, provide for a return on unrecovered capital . . . .[134]

As the PAS urged, "If the amount attributed to a tariff element in the TSM ceiling formula in any given year does not represent the amount for that specific tariff element that can be collected through TSM, what does that number represent and what is it doing in the TSM model?"[135] The plain language of the Settlement suggests that the depreciation schedule in TSM was intended to and has been used to recover investment. We also find based on our review of confidential documents produced during the hearing that the TAPS Carriers themselves viewed TSM depreciation as investment recovery.[136]

There is no reason for us to use the depreciation schedule that might have been adopted had TAPS rates been approved from 1977-1996, rather than the schedule that was used to recover investment. The Carriers must make a persuasive case that the TSM depreciation amounts do *not* represent their opportunity to recover their investment.

(i) <u>The Carriers fail to support the contention that using TSM depreciation charges for calculating rate base is "cherry picking" and denies a reasonable return</u>

The Carriers' use of straight-line depreciation hinges on their contention in this case that the depreciation term within TSM was not really intended to provide the Carriers with an opportunity to recover investment. The Carriers contend that the TSM can be considered only as a package, and that none of its elements has meaning

[134]BWF-4 at 27 (*emphasis added*); *see also* 29-ABJ-W at 16, 19, 21.

[135]P-1 (RAF) at 26-27.

[136]*See*, e.g., 110-RGV-E at RTSXPA 221761, RTSXPA 221768; 116-RGV-E, Bates number RTSXBP 325202 and 325203.

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outside the context of the Settlement.[137] They assert that TSM depreciation is not depreciation;[138] it is only one of the many components of TSM. Carriers contend that only the complete *package* of TSM elements, rather than any individual element, provides the Carriers with an opportunity to recover their investment.[139] The Carriers contend that using the TSM depreciation schedule to determine year-end 1996 rate base thus amounts to "cherry picking." We disagree.

"Cherry picking" is choosing what is desirable for a certain outcome and leaving the undesirable elements. Our role is to choose the most appropriate depreciation schedule based on the record before us.[140] There is no dispute in the record about the amount of depreciation that has been charged for the last twenty years under the rates calculated using TSM. Principles of equity and fairness require us to base our finding on the amount of depreciation that the shippers have been charged to date when we are determining the year-end 1996 rate base. In setting rates for 1997 through 2000, we must insure that shippers do not pay twice for the same Carrier investment. As the PAS suggested, "It is fundamental that historical depreciation taken

[137]*Initial Post-hearing Brief of the Indicated TAPS Carriers*, July 16, 2001, at 54; T-9 (ABJ) at 36.

[138]*See* T-5 (ABJ) 24-25.

[139]The Carriers admit that both "operating expenses" (Tr. (BWF) 2154) and "DR&R" (*see Initial Post-hearing Brief of the Indicated TAPS Carriers, dated July 16, 2001,* at 28-29) as used within TSM have their usual meaning. Accordingly, their claim is really that the remaining elements of the "TSM package" must cover return of investment, return on investment, and income taxes.

[140]Carriers' citation to *Lopez v. Public Employees*, 20 P.3d 568 (Alaska 2001), is not on point. It addresses the probative value of settlements. The court in *Lopez* held that it was not error for the Public Employees Retirement Board to exclude evidence of a settlement agreement from the record. The plaintiff sought to introduce it as evidence of an admission by the defendant and the Board properly excluded it as hearsay. There are no allegations in this case that the Intrastate Settlement Agreement is hearsay.

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by the Carriers to justify tariffs actually collected since the beginning of the pipeline be used in the rates for 1997-2000 no matter what methodology is used."[141]

The Carriers suggest not only that the Settlement must be allowed to continue through 2011 to receive the benefit of their bargain but also that the Settlement fails to fully compensate the Carriers for costs.[142] The Carriers assert that if the TSM depreciation schedule is used in a consistent DOC to set year-end 1996 rate base,[143] then they will be deprived of an opportunity to recover capital costs (which include both return on and of capital investment). The Carriers point out that through 1989, the Original Rate Base portion of TSM earned a 6.4 percent *real* return; New Rate Base continues to earn this 6.4 percent real return.[144] This figure, the Carriers suggest, is far too low given the risks associated with TAPS.[145] The Carriers contend that TSM was designed to "make up" for this underrecovery in the later years of operation through its Deferred Return and Allowance Per Barrel components.[146] Accordingly, the Carriers assert that the TSM must be allowed to run its course so that they can earn an adequate return on their investment.[147]

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[141]PAS Initial Post-hearing Brief at 9.

[142]T-9 (ABJ) 57.

[143]The Carriers acknowledge that a DOC may be "consistent" under virtually any depreciation schedule, (Tr. 1670-71 (ABJ), although they generally use the term "consistent DOC" to refer to their DOC methodology that employs straight-line depreciation.

[144]T-6 (WBT) 26. Dr. Haas, testifying for the State of Alaska, urged that due to details in its application the real return was actually only 5.5 percent overall. The Carriers' reliance on the TSM rates of return as a basis for indicating an actual rate of return is inconsistent with their contention that labels within TSM cannot be relied upon to reflect economic reality.

[145]T-6 (WBT) 26-28.

[146]T-5 (ABJ) 40; T-6 (WBT) 26.

[147]*See* T-1.(ABJ) 4; T-5 (ABJ) 41, 43.

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Tesoro, Williams and the PAS urge, however, that the rate of return provided by TSM is actually far greater than 6.4 percent.[148] The PAS argues, for example, that because the TSM presumes a 100 percent equity capital structure, while its true equity position has been considerably less, TSM actually generates a rate of return that is far greater than 6.4 percent.[149] Further, Williams, Tesoro, and the PAS all argue that the TSM's allowance per barrel (ABP) generates returns on Original Rate Base that are far in excess of what capital markets require.[150] These parties conclude that no "off book" deferred return is required to compensate the Carriers for "underrecovery" in the early years of operation.

As we note in Part IV Section C.4.f, a 6.4 percent real rate of return would often be inadequate to provide TAPS investors with appropriate compensation for the risk that they incur. However, as we discuss in Part IV Section B.1, a 100 percent equity capital structure is also not appropriate in a ratemaking context in which rates must reflect prudently incurred costs. Those conflicting elements, without further analysis, make the Carriers' actual returns indiscernible. The Carriers have failed to provide direct evidence of what they believe their past return to be.[151] Therefore, we

[148]BEW-44; RAF-3 (Revised); *see* JFB-9, line 12.

[149]The concerns about capital structure are two-fold. On the one hand, the actual fact of debt financing and the tax advantages conferred by debt mean that TSM provides an excessive income tax allowance relative to its putative 6.4 percent return. *See* BEW-44. On the other hand, the PAS contends that providing a deferred return to the inflation component of this return for debt-financed capital is inappropriate. *See* P-1 (RAF) 13-14; RAF-5 (Rev.) Schedule 2.

[150]P-1 (RAF) 14; RAF-3; RAF-4; JFB-2 Schedule F; *Williams Alaska Petroleum Inc.'s Post-hearing Initial Brief* at 27; BEW-34; BEW-44.

[151]Tr. 3493-94 (RGV).

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find the Carriers fail to provide sufficient evidence to support a finding that the TSM depreciation schedule has not allowed a sufficient opportunity for them to recover investment.

To verify that we do not deny the Carriers a fair opportunity to recover their investment, in Part V, *infra*, we compare the Carriers' costs of providing service, as measured by a DOC methodology using TSM depreciation charges, with the TSM's annual revenue requirement. We conclude that the Carriers have had an adequate opportunity to recover their investment and earn an appropriate return. Carriers have had the opportunity to earn $9.9 billion in excess of the reasonable and prudent costs of providing service.

(ii) <u>The Carriers' unrecovered investment analysis fails</u>

The Carriers do not provide evidence of the annual opportunity that TSM has provided for earning a rate of return from 1977-1996. Nor do the Carriers provide evidence of the annual achieved returns under the TSM for 1977-1996.[152] Neither do they suggest what returns will be in future years.[153] Instead, the Carriers present a method for determining their "actual" unrecovered investment to date.[154] They assert that this analysis shows that "actual" unrecovered investment is considerably greater

[152]The Carriers admit that they do not provide evidence on achieved returns under TSM. Tr. 3493-94 (RGV).

[153]The Carriers' assertion that achieved returns during 1977-1981 were too low appears inconsistent with their assertion that the internal rate of return generated by the TAPS is relatively insensitive to deviations in throughput from levels expected at the time of the Settlement (ABJ-3), even though from 1990 through 2000 these throughput differences provided Carriers with $760,487 million (nominal dollars) more than anticipated. *See* RAF-6 (Rev.). On its face, this suggests that revenue streams before 1990 are more important to providing the Carriers an adequate return than revenue streams in later years. This appears to conflict with the Carriers' current contention that future-year TSM rates are required to compensate for past inadequate returns.

[154]T-5 (ABJ) 26; RGV-15.

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than the rate base that would result from applying straight-line depreciation from 1977 through 1996.[155] Accordingly, Carriers assert that we should use straight-line depreciation to determine rate base for 1997-2000 to evaluation filed rates. [156]

The Carriers' unrecovered investment analysis, however, is unsuitable for checking the appropriateness of a straight-line DOC rate base. Although it attempts to depict actual investment recovery, actual investment recovery is irrelevant. We provide Carriers only with a reasonable *opportunity* to recover their investment. We do not look to their actual investment recovery. Determining rate base according to actual investment recovery can run afoul of the doctrine against retroactive ratemaking.[157]

Moreover, even if we were to look to "actual" investment recovery the Carriers' method of determining "actual" unrecovered investment is not reliable. The method measures unrecovered investment by subtracting the Carriers' operating expenses, return on remaining investment, and a tax allowance for that return from pipeline revenues. The remaining monies are finally applied to investment recovery. This approach is inadequate for the following three reasons: the Carriers' choice of conservative assumptions are not appropriate for determining actual investment recovery, the Carriers' unrecovered investment analysis produces an implausible result, and the Carriers choice of inputs is flawed.

(aa) The Carriers' conservative assumptions are inappropriate for setting cost-based rates

[155]T-6 (WBT) at 23; T-11 (RGV) 22.

[156]T-10 (WBT) 77. The Carriers seek to determine rate base only for purposes of establishing an appropriate comparative benchmark.

[157]The Carriers appear to agree. *Initial Post-hearing Brief of the Indicated TAPS Carriers,* dated July 16, 2001, at 6-21. The doctrine against retroactive ratemaking prohibits adjusting future rates to make up for past gains or losses. *See* Endnote 6.

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The Carriers assert that their measurement of unrecovered investment is conservative.[158] This "conservativeness" comes from two elements of their method. First, the Carriers state that as a matter of economic theory,[159] under-recovery of return *on* investment should be capitalized and added to rate base,[160] much like AFUDC. The Carriers, however, do not make these capitalizations despite their representation that return was inadequate from 1977 through 1981. Second, the Carriers point out that they include DR&R *revenues*, as provided by TSM, but do not include eventual DR&R *expenses*. The Carriers properly note that this also understates the amount of unrecovered investment.[161]

The Carriers assert that their analysis is intended to measure the "actual" level of unrecovered investment.[162] If so, it should not be a "conservative" measure, but rather an economically appropriate measure. One test of the Carriers' approach, from an economic perspective, is whether it produces credible results when "conservative" assumptions are removed and appropriate ones are employed.

We tested the Carriers' unrecovered investment analysis by removing the "conservative" assumptions.[163] Using the Carriers' suggestions for how inadequate return on investment might be capitalized,[164] and reducing pipeline revenues available

[158]T-9 (ABJ) 26, 66-68.

[159]"From a theoretical perspective, the appropriate treatment of such an event would be to capitalize the cost-of-service shortfall, and add that amount to rate base, in order to allow the Carriers an opportunity to recover those costs in the future." T-11 (RGV) at 25.

[160]T-5 (ABJ) 20; T-11 (RGV) 29.

[161]T-9 (ABJ) 34, 66.

[162]T-5 (ABJ) 26; RGV-15.

[163]Williams sponsored exhibits during the hearing that attempted this analysis. *See, e.g.,* 139-RGV-W. During cross-examination, the weaknesses in Williams' attempts were revealed. *See, e.g.,* Tr. 3587-90 (RGV).

[164]141-RGV-T; Tr. 3612-16 (RGV).

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to pay for investment recovery by TSM's DR&R allowance, we calculate the resulting purported level of unrecovered investment. Exhibit 5 shows that, according to the Carrier's framework, there has been *no* recovery of investment by the end of 1996.[165] Using the Carriers' unrecovered investment analysis, capitalized under-recovery continues to grow and Carrier rate base at the end of 1996 is more than 60 percent greater than the rate base at the beginning of pipeline operations.[166] This result is implausible.

It is not plausible that the Carriers would agree to a settlement that would not allow investment recovery. The TAPS generated over $50 billion in revenue from 1977-1996; operating expenses for that period were roughly $10.7 billion.[167] We cannot accept that the Carriers have nevertheless managed to recover *none* of the original investment. Although the Carriers and the State represent that significant amounts of unrecovered investment represent a good deal for the State (and, by extension, shippers),[168] we do not believe that the Carriers' shareholders would tolerate such a settlement.

(bb) The Carriers' unrecovered investment analysis is conceptually flawed

The Carriers' methodology inconsistently mixes regulatory and non-regulatory concepts and approaches. The Carriers incorporate accumulated deferred income taxes (ADIT) in their analysis of actual unrecovered investment. Doing so

[165] Exhibit 5, Schedule 1, Line 15.

[166] Exhibit 5, Schedule 6, Line 13.

[167] 11-ABJ-E.

[168] Tr. 3789-90 (JEH); *see* Tr. 2032-33 (ABJ).

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reduces the amount of unrecovered investment in 1996 by nearly $3 billion.[169] ADIT is a regulatory construct. It reflects money that Carriers may collect in rates to pay for taxes that are not yet owed. ADIT exists because of differences between regulatory and tax depreciation schedules.[170] Therefore, ADIT can exist only when a firm has a regulatorily approved depreciation schedule. The TAPS had none. Therefore, it did not generate such tax timing differences.[171] As an economic matter, ADIT cannot *actually* exist in the way that the Carriers have presumed because there have not been tax timing differences of the sort that they model. The Carriers' reliance on this regulatory concept is inconsistent with their failure to adopt the fundamental regulatory practice that return of investment is recovered before return on investment.

The Carriers' unrecovered investment analysis also creates contradictions. If the Carriers' unrecovered investment analysis[172] is meant to describe "actual" unrecovered investment, then the use of a rate of return that the Carriers believe they *should* have earned is inappropriate because as demonstrated in Exhibit 5 this leads to the result that not all investment is recovered. Investors would not tolerate that. On the other hand, if the Carriers' unrecovered investment analysis[173] is meant to describe the investment that *would* have been recovered had an appropriate regulatory regime been in place, then the methodology of taking return *on* investment (profit) before return *of* investment (depreciation) is inappropriate. Therefore, the Carriers'

[169]*See* BEW-T (W-3) 7-8; 143-RGV-C, RGV WP6.xls, Schedule 5 l. 15 wherein ADIT affects the return on investment that Carriers allege they should receive in any given year.

[170]BEW-T (W-3) 7.

[171]Firms that are not economically regulated generate no ADIT because no timing differences exist between regulatory and tax depreciation schedules.

[172]RGV-15.

[173]*Id.*

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unrecovered investment analysis fails. It should not be used to check the reasonableness of a DOC rate base.

(cc) The Carriers' inputs are flawed

We also find that the inputs that the Carriers use in their methodology are inappropriate. As explained in Part IV Section B.1 and B.3, (*infra*) respectively, the Carriers' choices for capital structure and rate of return are inappropriate. If appropriate inputs are chosen, then the Carriers' approach to measuring unrecovered investment, even when the Carriers' "conservative" assumptions are corrected, suggests that the Carriers had already completely recovered their investment by 1989[174] and by 1996 had earned an additional $8.4 billion in excess of costs.[175] Hence, the Carriers' unrecovered investment analysis fails to prove that using the TSM depreciation schedule to determine year-end 1996 rate base would deprive the Carriers of a reasonable opportunity to recover investment.

b) The Carriers' Additional Arguments for Using Straight-line Depreciation Are Unpersuasive

We now consider three additional Carrier arguments to support the use of straight-line depreciation for determining year-end 1996 rate base. The Carriers assert that straight-line depreciation is appropriate because: 1) the Uniform System of

[174] *See* Exhibit 6, Schedule 1, line 19.

[175] *See* Exhibit 6 Schedule 1, line 17. A comparison of Exhibit 6 with 143-RGV-C, RGV Workpaper 6, Schedule 10 reveals a failing in the Carriers' methodology and helps explain the widely differing results concerning unrecovered investment. By presuming that revenues go to return on investment before return of investment, the methodology effectively maximizes the tax payments purportedly made to Federal and State governments. Thus, the Commission's finding on appropriate capital structure and rate of return, when coupled with a Carrier-style unrecovered investment analysis, suggests a cumulative income tax allowance of something over $9 billion. *See* Exhibit 6 Schedule 1, Line 14. The Carriers' capital structure and rate of return, however, produces a cumulative tax allowance of over $17 billion. *See* RGV Workpaper 6 Schedule "Imputed Depr Rates," Line 9.

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Accounts requires using it; 2) the APUC used it in *Cook Inlet* and *Kenai,* and 3) the APUC accepted straight-line depreciation for TAPS when it accepted the 1982 depreciation stipulation. As further explained below, none of these rationales justifies using straight-line depreciation.

(i) The use of straight-line depreciation in FERC's Form 6 does not make straight-line depreciation appropriate for ratemaking on TAPS

The Carriers urge that benchmark rates should use straight-line depreciation because the FERC's Form 6 records straight-line depreciation. We disagree. The FERC requires all pipeline companies to file a FERC Form 6 so that FERC can compare the costs of different pipelines.[176] The FERC also requires pipeline companies filing FERC Form 6 to use the Uniform System of Accounts. The Uniform System of Accounts requires pipeline companies to use straight-line depreciation unless an alternative is approved.

Carrier witnesses admit that they do not use the straight-line depreciation shown in FERC Form 6 ratemaking purposes. Carrier witness Smith explained that "[t]he Form 6 was not intended as it was created to be a ratemaking document . . . ."[177] When asked whether the FERC would use FERC Form 6 to determine the components of a methodology, witness Smith responded, "No, the FERC Form 6 is—is an accounting and regulatory document. It is not a—a manual on how to develop a rate base."[178] When Carrier Witness Folmar was asked specifically if the numbers reported on the FERC Form 6 could be used for rate purposes, he responded, "With the

[176]Tr. 2411-12(LPS).
[177]Tr. 2370 (LPS).
[178]Tr. 2473 (LPS); *see also* Tr. 2371(LPS).

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approval—or with the acceptance of TSM agreements, no."[179] He stated that the numbers used in the Uniform System of Accounts were regulatorily reported numbers but were not used in setting rates.[180] Finally, Carrier witness Van Hoecke encouraged us to rely on ratemaking numbers and not on accounting requirements.[181]

Therefore, although the FERC Form 6 may provide helpful information to the FERC for indexing pipeline companies' costs and perhaps for measuring changes in pipeline rates, we find that it is not a compelling reason to choose straight-line depreciation as the appropriate depreciation schedule for ratemaking on TAPS.

(ii) <u>*Cook Inlet* and *Kenai* do not require us to adopt straight-line depreciation</u>

The Carriers assert that the APUC holdings in *Cook Inlet* and *Kenai* also support use of straight-line depreciation to compute a TAPS rate base against which to measure the rates under investigation. In both *Cook Inlet* and *Kenai* a rate base had to be established in the middle of the life of the line. In *Cook Inlet,* Cook Inlet Pipe Line Company's rates were calculated under the ICC valuation methodology. The ICC valuation methodology allowed companies to include depreciation charges as an element of rates. Depreciation charges were designed to recover the cost of the property over time and were calculated on a straight-line basis. Under the ICC valuation methodology, rate base was not calculated solely by deducting those same depreciation charges from the original cost of the property. Because straight-line depreciation is included in both ICC valuation and DOC rates, the amount of accumulated depreciation under both methodologies is the same.

179 Tr. 2174 (BWF).
180 Tr. 2301 (BWF).
181 Tr. 3146 (RGV).

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When the APUC established a DOC rate base in the middle of the life of the Cook Inlet line, it used the actual straight-line depreciation charges included under the ICC valuation methodology to calculate the new DOC rate base.[182] Therefore, rather than providing precedent for use of straight-line depreciation when establishing a rate base in the middle of the life of the line, *Cook Inlet* more precisely stands for the proposition that the actual depreciation charges should be used for calculating future rates.

In *Kenai,* the APUC could not determine which methodology the Kenai Pipe Line Company (KPL) had used to calculate prior intrastate rates. The APUC presumed that prior intrastate rates were calculated under the ICC valuation methodology and under those facts, the APUC concluded that the same straight-line depreciation that was included or was includable in rates computed under the ICC valuation methodology should be used in calculating the new rates. The APUC stated:

> Under the valuation methodology depreciation was included in revenue requirement to the same extent it would have been under DOC. Thus, amounts that have been deducted from the DOC rate base through depreciation have actually been recovered by KPL.[183]

The APUC ordered the use of straight-line depreciation in *Kenai* and *Cook Inlet* because straight–line depreciation was the depreciation actually used to calculate prior rates. *Kenai* and *Cook Inlet*, therefore, stand for the proposition that when establishing a DOC rate base for an existing pipeline in the middle of the operating life we should apply the depreciation actually used to establish prior rates rather than the depreciation that would or should have been used. Therefore, the Carriers' citations to

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[182]*Re Cook Inlet Pipe Line Company*, 6 APUC 527, 536 (1985).

[183]*Re Kenai Pipe Line Co.*, 12 APUC 425, 440, 1992 WL 696192 (Alaska P.U.C., 1992) *(footnote omitted)*.

Cook Inlet and *Kenai* as precedent for using straight-line depreciation in this case to calculate a DOC rate base are not persuasive. Instead *Cook Inlet* and *Kenai* support using TSM depreciation charges to calculate a mid-stream rate base because that depreciation schedule was used to establish the past rates charged to shippers.

(iii) <u>The APUC's acceptance of a depreciation stipulation for TAPS in an uncontested settlement is not binding once a subsequent settlement supersedes it and a non-stipulating shipper contests rates</u>

The Carriers assert a third rationale for using straight-line depreciation to calculate a rate base against which to test filed rates: the FERC and the APUC accepted a 1982 Depreciation Stipulation that adopted a straight-line depreciation schedule for TAPS.[184] The straight-line depreciation schedule was approved subject to conditions by the FERC and the APUC as an uncontested stipulation;[185] it was not altered or withdrawn.[186]

The APUC accepted the depreciation stipulation in 1982 in the context of the then pending (original) TAPS litigation. The unresolved depreciation issue at that time was the life of the line, not the depreciation rate.[187] Although the APUC accepted the depreciation stipulation as in the public interest, it did not adjudicate rates and never approved the depreciation stipulation as producing just and reasonable TAPS rates under AS 42.06.370(a).[188]

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[184]*Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 12-14.

[185]*Re Construction of the Trans Alaska Pipeline*, 4 APUC 338 (1982) at 339.

[186]BWF-2, Sec. III-5.

[187]*Re Construction of the Trans Alaska Pipeline*, 4 APUC 338 (1982) at 339.

[188]*Cook Inlet Pipe Line Co. v. Alaska Public Utilities Comm'n,* 836 P.2d 343, 353 (Alaska 1992).

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The 1982 Depreciation Stipulation might support the Carriers' position if this case were concerned with whether current shippers are "disadvantaged by the rate pattern established by TSM,"[189] or would have paid rates less favorable "than those they would have paid in the absence of TSM."[190] However, we are not engaged in a hypothetical exercise to determine what the rate base would have been if TSM had never been used to set rates.[191] Rather, we choose the depreciation schedule that -- when applied from 1977 through 1996 – actually provided the Carriers with an opportunity to recover their capital investment and yet will not force shippers to pay for that investment twice.[192]

The record reveals unequivocally that the Carriers have filed tariffs using the TSM depreciation schedule. When asked if Tesoro's rates have been calculated under TSM, Carrier witness Adam B. Jaffe responded, "That is my understanding, yes."[193] Similarly, when Carrier witness Billy W. Folmar was asked what depreciation schedule the Carriers used to set rates, he responded "TSM Depreciation."[194]

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[189] *TAPS Carriers' Prehearing Brief*, April 5, 2001, at 3.

[190] *Initial Post-hearing Brief of the Indicated TAPS Carriers*, July 16, 2001, at 40.

[191] In *Re Amerada Hess Pipeline Corporation*, Order P-97-4(79) (Order 79), dated April 10, 2000, we reiterated the APUC's warning when it originally allowed TSM rates that TSM rates would be subject to the same standards and procedures as if the Settlement had not been accepted. *Id.*, at 4. In saying this we did not imply that the Carriers should support their filed rates as if actual history had not transpired. In the context of Order 79, our meaning was clear: No presumption should be made that filed rates were just and reasonable simply because the Settlement had been accepted. In Order 79, we made clear that we intended to review the TAPS filed rates using the same standards and procedures that we use to review any filed rate.

[192] *Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 (RCA Oct. 29, 2001).

[193] Tr. 1717 (ABJ).

[194] Tr. 2302 (BWF).

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The filings that the Carriers have made confirm that they have used an accelerated depreciation schedule for calculating intrastate rates.[195] The Carriers and the State represented at the time of the Settlement that TSM depreciation was investment recovery. Internal company documents also strongly suggest that the Carriers have viewed TSM depreciation as investment recovery.[196]

The Carriers nonetheless assert that the rates charged under the Settlement are consistent with the 1982 Depreciation Stipulation because the accelerated depreciation schedule in the Settlement only calculates depreciation for TSM ceiling rates.[197] They reason that if we are looking at rates as "if the Intrastate Settlement Agreement had not been accepted" then the only depreciation schedule truly accepted by the APUC is the 1982 Depreciation Stipulation.

We find this argument unpersuasive. TSM has been used to establish rates for more than twenty years. Tesoro witness Williams testified that "I am not aware of any instance where any one has been able to go back and change depreciation that has already been collected in rates."[198] Williams went on to testify that he could not think of any circumstances where FERC would not consider the depreciation already included in rates to be recovered investment for the purposes of rate setting.[199] When Tesoro witness Brown was asked if he had ever seen "an instance in which the

[195] *See* 30 BWF-E.

[196] *See*, e.g., 110-RGV-E at RTSXPA 221761, RTSXPA 221768; 116-RGV-E at RTSXBP 325202-03.

[197] However, the Settlement that incorporated TSM for use in setting maximum rates provides in Section III-5 that an earlier stipulation can continue to be used only if it is not inconsistent with TSM. *See* BWF-2 III-5. Williams witness Johnstone testified that the 1982 Depreciation Stipulation was inconsistent with TSM because it has a different depreciation schedule than was used to set rates on the TAPS and calculate refunds. Tr. 4207-08 (WBJ).

[198] Tr. 4910 (KAW).

[199] Tr. 4911 (KAW).

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accumulated depreciation was based on something other than the amounts actually collected in rates," he testified: "I began my career in the industry in ratemaking in 1957, and I have never seen anything like what is being proposed by the TAPS Carriers and I really feel that if it were proposed to the FERC the first thing they would do would be to disallow that proposal."[200] PAS witness Fineberg explained

> In the Carriers' hypothetical DOC tariff for 1997-2000, the replacement of the actual, hyper-accelerated collections under the TSM with hypothetical, Form 6 depreciation reduces the historical capital actually recovered, thereby artificially increasing the remaining rate base. This is an inappropriate substitution based on illusory data. TAPS Carriers in fact had already recouped the vast majority of the their original investment by 1997 through TSM's hyper-accelerated depreciation schedule. For this reason, the comparison [of the Carriers' filed rates to benchmark rates] proposed by the Carriers cannot be considered valid.[201]

The 1982 Depreciation Stipulation is therefore not relevant to establishing a year-end 1996 rate base. It was superceded and has never been used to calculate either ceiling or filed TAPS rates.

We note that the depreciation amounts that yield TSM maximum ceiling rates provided the Carriers with the opportunity to fully recover their investment.[202] If the Carriers have voluntarily chosen to file rates that are less than TSM ceiling rates and thereby curtail their opportunity, the Carriers nevertheless have had an opportunity to recover and we cannot require shippers to pay for that opportunity twice. Therefore, the only depreciation schedule that can be applied and meet the twin goals of providing Carriers the opportunity to recover their investment and also does not force shippers to

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[200]Tr. 5389 (JFB).

[201]P-1 (RAF) at 30.

[202]*See* n.550. We have also determined that the Carriers have had ample opportunity to both recover their investment and earn a reasonable contemporaneous return. *See* Part V Section B. and Exhibit 7.

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face paying for that investment twice is the depreciation schedule used in calculating past tariffs, *i.e.*, the TSM depreciation schedule.

In addition to the legal and logical arguments discussed above, the Carriers use of straight-line depreciation to calculate their benchmark rates and to perform an unrecovered investment analysis is untenable. Doing so provides the Carriers with overrecovery of investment and potentially forces shippers to pay for that investment twice. We therefore find that the Carriers have failed to adequately support the filed rates as just and reasonable.

To confirm this finding, in the next section we apply a DOC methodology from the beginning of TAPS operation to year-end 1996 to establish a year-end 1996 rate base from which to calculate 1997-2000 rates as required by *Cook Inlet*[203]. In doing so, we confirm that the Carriers rates are 57 percent higher than just and reasonable rates.

IV. WE COMPUTE A $669 MILLION YEAR-END 1996 RATE BASE USING DOC METHODOLOGY CONSISTENTLY APPLIED FROM THE BEGINNING OF TAPS OPERATIONS

A DOC methodology applied from the beginning of the life of the line is the most reliable method for establishing a rate base in the middle of the operating life of a line.[204] No party in this proceeding disagrees. We review the record to determine the appropriate inputs for calculating the year-end 1996 intrastate TAPS rate base using a DOC methodology.

The DOC methodology formula is RR = [r (V-D)] + [OE + d + t] where

RR = revenue requirement

[203]*Re Cook Inlet Pipe Line Co.*, 6 APUC 527 (1985).

[204]*Re Cook Inlet Pipe Line Co.*, 6 APUC 527 (1985).

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r = after-tax return

V = sum of prudently incurred capital expenditures, allowance for funds used during construction (AFUDC), and working capital adjusted for Accumulated Deferred Income Tax (ADIT) and retirements

D = accumulated depreciation, adjusted for retirements

OE = operating and maintenance expenses

d = annual depreciation charges

t = taxes.

If an oil pipeline must be dismantled at the end of its useful life, a pipeline carrier is also entitled to recover the reasonable dismantling, restoration and removal (DR&R) costs.[205]

In the formula above, the rate base equals V-D. In the following sections, we establish the elements necessary to calculate rate base: A) The total amount of prudent investment (Carrier property balances) including capital and retirements, B) AFUDC amounts when the associated property is first brought into service; C) ADIT, and D) the depreciation schedule used to determine accumulated depreciation from 1977-1996.

A. Carrier Property Balances

Rate base consists of both depreciable and non-depreciable property in service. In this case non-depreciable property consists of Working Capital and Land.[206]

[205]TSM includes DR&R. For purpose of this analysis, DR&R is not considered because this analysis establishes rate base. DR&R, however, is relevant when discussing rates. *See* Part VI, Section E.

[206]*See, e.g.,* 143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls, Schedule 2; Line 13; 225-JFB-T, Workpaper 2, Line 13; 30-BWF-E ('77-'83) Lines 82 and 83; 31-BWF-E ('84-'00) Lines 82-83.

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Carrier property balances that may earn AFUDC[207] include both depreciable property and land. An allowance for AFUDC is a reasonable element to include in rates because it is appropriate to compensate for the capital costs incurred constructing the pipeline before it is placed into service.

We first determine initial Carrier property balance. The record presents four Carrier property issues: 1) what the actual level of capital expenditures in any given year should be; 2) whether a significant portion of Carrier expenditures during construction, $450 million, should be removed from rate base because of imprudence; 3) what the appropriate allowance for Working Capital should be, and 4) how to calculate property retirements. We address each in turn.

1. <u>Capital Expenditure Amounts</u>

The parties do not agree on the actual level of capital expenditures in any given year. Tesoro relies upon the capital expenditure data contained in the TSM spreadsheet filings for 1984-2000. For the years before 1984, Tesoro relies on data[208] contained in the TSM-6 illustrative model.[209] The Carriers and Williams use the

[207]AFUDC is Allowance for Funds Used During Construction. The amount of accumulated AFUDC for a particular item under construction is added to rate base at the same time the CWIP (Construction Work in Progress) balance attributable to that item is transferred to rate base, i.e., when the property is placed in service. BONBRIGHT, JAMES C., PRINCIPLES OF PUBLIC UTILITY RATES 246-253 (1988).

[208]Tr. 5129 (JFB).

[209]31-BWF-E; *see also* BWF-6 at 5-12; T-8 (BWF) 2. The TSM-6 model was attached to the *Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offe*r (BWF-4). TSM-6 shows the derivation of various rate base balances that were embodied within TSM as of 1984, by tracing various Carrier property balances back to 1968. The illustrative model for how TSM was intended to operate (BWF-3 at 56) agrees with TSM-6 for 1984 and 1985 (the years of overlap). BWF-3 at 34.

TSM-6 shows, among other things, the derivation of TSM's 1984 starting AFUDC balance (BWF-3 at 38), the annual depreciation taken during 1977-1983 to derive the Settlement's starting rate base in 1984 (BWF-3 at 19), and the amortization schedule of the $450 million in excluded costs (BWF-3 at 14).

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property balance data entered into the record in earlier TAPS proceedings for years before 1977, where no annual records were available.[210] The Carriers and Williams rely on the property balances that the Carriers filed in their annual reports with this Commission and the FERC for years after 1977.

The difference between the two sets of capital expenditure data in any given year is occasionally substantial. For example, in the first half of 1977, the Carrier-sponsored property additions data are $39.8 million more than the figure sponsored by Tesoro.[211] In 1978, the Carrier-sponsored property addition figure is $56.1 million less than the one sponsored by Tesoro. However, for twenty-three out of thirty-three years, the difference is less than $1 million.[212]

On a cumulative basis, the Carrier-sponsored property addition data exceed Tesoro's during 1973-1977, reaching a peak surplus level of $56.4 million mid-way through 1977. A sizeable cumulative deficit is then accrued from 1978-1982, reaching a peak cumulative deficit of $21.5 million in 1979. From 1983-1996 the cumulative difference between the two sponsored data sets remains below $1 million.[213] The total property balances are thus cumulatively essentially the same. The choice of one set of property additions over another primarily affects the size of the AFUDC balance. Because the Carrier property addition data is greater in the earliest years,

[210]T-7 (RGV):4. As indicated below, Williams follows TSM and makes a downward adjustment of $450 million to the Carrier property balances; the Carriers do not.

[211]212-FJH-T.

[212]*See* 212-FJH-T.

[213]212-FJH-T.

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