EL PASO ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31, 2019	2018	2017
Cash Flows From Operating Activities:			
Net income	$ 123,037	$ 84,315	$ 98,261
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	102,072	96,382	90,843
Amortization of nuclear fuel	41,033	38,176	42,476
Deferred income taxes, net	27,143	29,118	49,394
Allowance for equity funds used during construction	(2,545)	(3,453)	(3,025)
Other amortization and accretion	18,278	20,830	18,954
Net losses (gains) on decommissioning trust funds	(38,514)	12,967	(10,626)
Other operating activities	844	(38)	(692)
Change in:			
Accounts receivable	(101)	5,712	(138)
Inventories	(5,512)	(4,117)	(3,073)
Prepayments and other	(897)	(4,419)	(692)
Accounts payable	4,683	(2,233)	1,407
Taxes accrued	11,195	(5,487)	1,840
Interest accrued	(2,282)	4,008	(817)
Net over-collection of fuel revenues	7,368	4,822	17,093
Other current liabilities	(937)	9,289	(100)
Deferred charges and credits	(9,721)	(475)	(12,544)
Net cash provided by operating activities	275,144	285,397	288,561
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(222,203)	(240,021)	(199,896)
Cash additions to nuclear fuel	(36,800)	(38,354)	(38,481)
Insurance proceeds received for equipment	—	5,351	9,591
Capitalized interest and AFUDC:			
Utility property, plant and equipment	(6,560)	(7,065)	(6,000)
Nuclear fuel and other	(5,729)	(5,483)	(5,022)
Allowance for equity funds used during construction	2,545	3,453	3,025
Decommissioning trust funds:			
Purchases, including funding of $2.1 million, $2.1 million and $3.8 million, respectively	(377,415)	(86,366)	(102,920)
Sales and maturities	370,677	80,732	97,037
Proceeds from sale of property, plant and equipment	368	287	281
Other investing activities	(2,409)	4,186	(1,559)
Net cash used for investing activities	(277,526)	(283,280)	(243,944)
Cash Flows From Financing Activities:			
Dividends paid	(61,718)	(57,539)	(53,337)
Borrowings under the revolving credit facility:			
Proceeds	566,321	567,894	638,458
Payments	(501,727)	(692,220)	(546,499)
Pollution control bonds:			
Proceeds	100,600	—	—
Payments	(100,600)	—	(33,300)
Proceeds from issuance of senior notes	—	125,000	—
Proceeds from issuance of RGRT senior notes	—	65,000	—
Payments on maturing RGRT senior notes	—	—	(50,000)
Other financing activities	(2,576)	(4,342)	(1,369)
Net cash provided by (used for) financing activities	300	3,793	(46,047)
Net increase (decrease) in cash and cash equivalents	(2,082)	5,910	(1,430)
Cash and cash equivalents at beginning of period	12,900	6,990	8,420
Cash and cash equivalents at end of period	$ 10,818	$ 12,900	$ 6,990

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
BALANCE SHEETS

ASSETS (In thousands)	December 31, 2017	December 31, 2016
Utility plant:		
Electric plant in service	$ 3,982,095	$ 3,791,566
Less accumulated depreciation and amortization	(1,320,175)	(1,244,332)
Net plant in service	2,661,920	2,547,234
Construction work in progress	146,059	154,738
Nuclear fuel; includes fuel in process of $59,689 and $57,315, respectively	194,933	194,842
Less accumulated amortization	(74,475)	(75,602)
Net nuclear fuel	120,458	119,240
Net utility plant	2,928,437	2,821,212
Current assets:		
Cash and cash equivalents	6,990	8,420
Accounts receivable, principally trade, net of allowance for doubtful accounts of $2,300 and $2,156, respectively	88,585	88,452
Inventories, at cost	50,910	47,216
Under-collection of fuel revenues	—	11,123
Prepayments and other	10,307	8,988
Total current assets	156,792	164,199
Deferred charges and other assets:		
Decommissioning trust funds	286,866	255,708
Regulatory assets	96,036	118,861
Other	16,232	16,298
Total deferred charges and other assets	399,134	390,867
Total assets	$ 3,484,363	$ 3,376,278

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
BALANCE SHEETS (Continued)

CAPITALIZATION AND LIABILITIES (In thousands except for share data)	December 31, 2017	2016
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 65,694,829 and 65,685,615 shares issued, and 133,859 and 137,017 restricted shares, respectively	$ 65,829	$ 65,823
Capital in excess of stated value	326,117	322,643
Retained earnings	1,159,667	1,114,561
Accumulated other comprehensive income (loss), net of tax	11,058	(7,116)
	1,562,671	1,495,911
Treasury stock, 25,244,350 and 25,304,914 shares, respectively, at cost	(420,506)	(421,515)
Common stock equity	1,142,165	1,074,396
Long-term debt, net of current portion	1,195,988	1,195,513
Total capitalization	2,338,153	2,269,909
Current liabilities:		
Current maturities of long-term debt	—	83,143
Short-term borrowings under the revolving credit facility	173,533	81,574
Accounts payable, principally trade	59,270	62,953
Taxes accrued	35,660	32,488
Interest accrued	12,470	13,287
Over-collection of fuel revenues	6,225	255
Other	29,067	29,709
Total current liabilities	316,225	303,409
Deferred credits and other liabilities:		
Accumulated deferred income taxes	305,023	555,066
Accrued pension liability	83,838	92,768
Accrued post-retirement benefit liability	26,417	34,400
Asset retirement obligation	93,029	81,800
Regulatory liabilities	296,685	18,435
Other	24,993	20,491
Total deferred credits and other liabilities	829,985	802,960
Commitments and contingencies		
Total capitalization and liabilities	$ 3,484,363	$ 3,376,278

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF OPERATIONS
(In thousands except for share data)

	Years Ended December 31,		
	2017	**2016**	**2015**
Operating revenues	$ 916,797	$ 886,936	$ 849,869
Energy expenses:			
Fuel	185,069	173,738	188,400
Purchased and interchanged power	59,682	59,727	53,545
	244,751	233,465	241,945
Operating revenues net of energy expenses	672,046	653,471	607,924
Other operating expenses:			
Other operations	242,628	242,014	242,950
Maintenance	69,458	66,746	65,223
Depreciation and amortization	90,843	84,317	89,824
Taxes other than income taxes	70,863	65,533	63,736
	473,792	458,610	461,733
Operating income	198,254	194,861	146,191
Other income (deductions):			
Allowance for equity funds used during construction	3,025	7,023	10,639
Investment and interest income, net	17,757	14,083	17,508
Miscellaneous non-operating income	715	1,292	2,062
Miscellaneous non-operating deductions	(3,125)	(3,699)	(4,328)
	18,372	18,699	25,881
Interest charges (credits):			
Interest on long-term debt and revolving credit facility	72,970	71,544	65,851
Other interest	2,388	1,303	1,313
Capitalized interest	(5,022)	(4,990)	(4,968)
Allowance for borrowed funds used during construction	(2,975)	(4,983)	(6,937)
	67,361	62,874	55,259
Income before income taxes	149,265	150,686	116,813
Income tax expense	51,004	53,918	34,895
Net income	$ 98,261	$ 96,768	$ 81,918
Basic earnings per share	$ 2.42	$ 2.39	$ 2.03
Diluted earnings per share	$ 2.42	$ 2.39	$ 2.03
Dividends declared per share of common stock	$ 1.315	$ 1.225	$ 1.165
Weighted average number of shares outstanding	40,414,556	40,350,688	40,274,986
Weighted average number of shares and dilutive potential shares outstanding	40,535,191	40,408,033	40,308,562

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2017	**2016**	**2015**
Cash Flows From Operating Activities:			
Net income	$ 98,261	$ 96,768	$ 81,918
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	90,843	84,317	89,824
Amortization of nuclear fuel	42,476	43,748	43,099
Deferred income taxes, net	49,394	50,510	30,846
Allowance for equity funds used during construction	(3,025)	(7,023)	(10,639)
Other amortization and accretion	18,954	17,295	17,707
Gain on sale of property, plant and equipment	—	(545)	(658)
Net gains on sale of decommissioning trust funds	(10,626)	(7,640)	(11,114)
Other operating activities	(692)	1,279	517
Change in:			
Accounts receivable	(138)	(17,511)	4,839
Inventories	(3,073)	265	(2,859)
Net over-collection (under-collection) of fuel revenues	17,093	(14,891)	13,344
Prepayments and other	(692)	(1,184)	(3,984)
Accounts payable	1,407	(2,140)	(11,235)
Taxes accrued	1,840	1,945	4,512
Other current liabilities	(917)	2,022	3,719
Deferred charges and credits	(12,544)	(16,065)	(3,165)
Net cash provided by operating activities	288,561	231,150	246,671
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(190,305)	(225,361)	(281,458)
Cash additions to nuclear fuel	(38,481)	(42,383)	(41,966)
Capitalized interest and AFUDC:			
Utility property, plant and equipment	(6,000)	(12,006)	(17,576)
Nuclear fuel and other	(5,022)	(4,990)	(4,968)
Allowance for equity funds used during construction	3,025	7,023	10,639
Decommissioning trust funds:			
Purchases, including funding of $3.8 million, $4.5 million and $4.5 million, respectively	(102,920)	(99,497)	(110,223)
Sales and maturities	97,037	91,268	102,567
Proceeds from sale of property, plant and equipment	281	4,841	721
Other investing activities	(1,559)	5,373	(470)
Net cash used for investing activities	(243,944)	(275,732)	(342,734)
Cash Flows From Financing Activities:			
Dividends paid	(53,337)	(49,603)	(47,059)
Borrowings under the revolving credit facility:			
Proceeds	638,458	355,607	344,398
Payments	(546,499)	(415,771)	(217,192)
Payment on maturing RGRT senior notes	(50,000)	—	(15,000)
Payment on maturing pollution control bonds	(33,300)	—	—
Proceeds from issuance of senior notes	—	157,052	—
Other financing activities	(1,369)	(2,432)	(1,439)
Net cash provided by (used for) financing activities	(46,047)	44,853	63,708
Net increase (decrease) in cash and cash equivalents	(1,430)	271	(32,355)
Cash and cash equivalents at beginning of period	8,420	8,149	40,504
Cash and cash equivalents at end of period	$ 6,990	$ 8,420	$ 8,149

See accompanying notes to financial statements.

PUBLIC

TIEC 1-13 Attachment 3 is a CONFIDENTIAL and/or HIGHLY SENSITIVE PROTECTED MATERIALS attachment.

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
TEXAS INDUSTRIAL ENERGY CONSUMERS'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. TIEC 1-1 THROUGH TIEC 1-17

TIEC 1-14:

Please state whether EPE's regulated retail operations have any off balance sheet debt such as purchased power agreements and operating leases. If the answer is "yes," provide the amount of each off-balance sheet debt item and estimate the related imputed interest and amortization expense associated with these off-balance sheet debt equivalents specific to EPE's jurisdictional regulated retail electric operations.

RESPONSE:

No. El Paso Electric does not have any off-balance sheet debt such as purchased power agreements and operating leases. El Paso Electric Company has lease and purchased power agreements for which debt could be imputed by the rating agencies; however, Fitch and Moody's did not make any specific imputations of debt associated with these agreements in their latest analysis.

Preparer: Richard Gonzalez	Title: Manager – Cash Management & Investor Relations
Sponsor: Lisa Budtke	Title: Director – Treasury Services & Investor Relations

SOAH DOCKET NO. 473-21-2606
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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

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TEXAS INDUSTRIAL ENERGY CONSUMERS'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. TIEC 1-1 THROUGH TIEC 1-17

TIEC 1-15:

Do any of EPE's outstanding long-term debt issues have call provisions? If the answer is "yes," please provide a list of the callable issues with the following: a) outstanding balance, b) issuance date, c) maturity date, d) coupon payment percent, e) annual interest expense, and f) call price (as a percent of par).

RESPONSE:

All El Paso Electric debt issuances included in the capital structure have "make whole" call provisions. The "make whole" call provisions require that investor be fully compensated or "made whole" for future principal and interest payments. The "make whole" redemption feature would makes utilizing this call provision uneconomical.

The following long-term debt issuances have optional call provisions at par, as well as "make whole" call provisions. Listed below is the requested information for the optional call provisions.

Series Description	Outstanding Balance	Issuance Date	Maturity Date	Coupon Rate	Annual Interest Expense	Call Price
5.0% Senior Notes (a)	$300,000,000	12/1/2014 3/24/2016	12/1/2044	5.000%	$15,000,000	100% of the principal on or after 6/1/2044
3.3% Senior Notes	$150,000,000	12/6/2012	12/15/2022	3.300%	$4,950,000	100% of the principal on or after 9/15/2022
Maricopa Ser. 2009 A (b)	$63,500,000	3/26/2009	2/1/2040	3.600%	$2,286,000	100% of the principal on or after 06/01/2029
Maricopa Ser. 2009 B (b)	$37,100,000	3/26/2009	4/1/2040	3.600%	$1,335,600	100% of the principal on or after 06/01/2029
Maricopa Ser. 2012 A	$59,235,000	8/28/2012	8/1/2042	4.500%	$2,665,575	100% of the principal on or after 08/01/2022

a) On March 24, 2016 El Paso Electric re-opened and issued an additional $150 million of its 5% Senior Notes due December 1, 2044. $150 million was previously issued on December 1, 2014, for a total principal amount outstanding of $300 million.

b) El Paso Electric purchased, in lieu of redemption, all of the 2009 Series A 7.25% PCBs with an aggregate principal amount of $63.5 million, and all of the 2009 Series B 7.25% PCBs with an aggregate principal amount of $37.1 million, on February 1, 2019 and April 1, 2019, respectively, utilizing funds borrowed under the RCF. On May 22, 2019, the Company reoffered and sold $63.5 million aggregate principal amount of 2009 Series A 7.25% PCBs and $37.1 million aggregate principal amount of 2009 Series B 7.25% PCBs with a fixed interest rate of 3.60% per annum until the PCBs mature on February 1, 2040 and April 1, 2040, respectively. Proceeds from the remarketing of the PCBs were primarily used to repay outstanding short-term borrowings under the RCF.

Preparer: Richard Gonzalez — Title: Manager – Cash Management & Investor Relations

Sponsor: Lisa Budtke — Title: Director – Treasury Services and Investor Relations

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
TEXAS INDUSTRIAL ENERGY CONSUMERS'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. TIEC 1-1 THROUGH TIEC 1-17

TIEC 1-16:

Has EPE performed any debt refinancing feasibility studies on its outstanding debt issues? If the answer is "yes," please provide the following:

a. A detailed description of the results from the study.
b. A detailed description of the conclusions(s) made by EPE based on the results of the study.
c. All debt refinancing feasibility studies in electronic format with all formulas intact.

RESPONSE:

No. El Paso Electric Company ("EPE") has not performed any debt refinancing feasibility studies because none of the outstanding debt is callable at this time without the make whole provision outlined in EPE's response to TIEC 1-15.

Preparer: Richard Gonzalez — Title: Manager – Cash Management & Investor Relations

Sponsor: Lisa Budtke — Title: Director – Treasury Services and Investor Relations

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
TEXAS INDUSTRIAL ENERGY CONSUMERS'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. TIEC 1-1 THROUGH TIEC 1-17

TIEC 1-17:

Please provide a copy of all academic publications or studies Ms. Nelson is familiar with that discuss the use of adjusted value line betas in the Empirical CAPM.

RESPONSE:

Ms. Nelson has not undertaken an exhaustive literature search; however, she is aware of at least two academic studies that discuss the use of adjusted Beta coefficients in the Empirical CAPM approach:

1. Robert Litzenberger, Krishna Ramaswamy, and Howard Sosin, "On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital", The Journal of Finance, Vol. XXXV, No. 2, May 1980 (provided as TIEC 1-17 Attachment 1)
2. Chrétien, Stéphane, and Frank Coggins. *Cost Of Equity For Energy Utilities: Beyond The CAPM.* Energy Studies Review, vol. 18, no. 2 (provided as TIEC 1-17 Attachment 2).

In the study by Litzenberger *et al.*, the authors discuss the use of the CAPM within the context of public utility rate cases to measure the cost of equity and found that the CAPM tends to understate the return for stocks such as utilities that have a Beta coefficient less than 1.0. Litzenberger *et al.* utilized both adjusted and raw Beta coefficients to develop their analysis. In both cases, the CAPM understated the return for utilities with Beta coefficients less than 1.0.

In the Chrétien and Coggins study, the authors studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of utilities. The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the Empirical CAPM ("ECAPM") I applied in my Direct Testimony. In the article, the ECAPM relied on Beta coefficients that were adjusted using the same approach applied by Value Line. As Chrétien and Coggins show, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

Preparer: Jennifer E. Nelson | Title: Assistant Vice President – Concentric Energy Advisors

Sponsor: Jennifer E. Nelson | Title: Assistant Vice President – Concentric Energy Advisors

THE JOURNAL OF FINANCE • VOL. XXXV, NO. 2 • MAY 1980

On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital

ROBERT LITZENBERGER, KRISHNA RAMASWAMY and HOWARD SOSIN*

I. Introduction

IN RECENT YEARS the Capital Asset Pricing Model (CAPM) has been used in several public utility rate cases to measure the cost of equity capital. In actual application, the cost of equity capital is frequently estimated as the annualized 90 day Treasury Bill rate plus a risk premium. The risk premium is obtained as the product of the average annual excess rate of return on a value weighted index of NYSE stocks (where the average is taken over a long period of time) and an estimate of the utility's NYSE beta.

Underlying this procedure is the assumption that risk premiums are *strictly* proportional to NYSE betas. However, this assumption is inconsistent with the academic empirical literature on CAPM. This literature supports a (non-proportional) linear relationship between risk premiums and NYSE betas with a positive intercept. Other empirical studies suggest that, in addition to betas, risk premiums are influenced by dividend yields and systematic skewness. Evidence presented in this literature is consistent with the predictions of CAPM models that account for margin restrictions on the borrowing of investors, divergent borrowing and lending rates, the existence of risky assets (such as bonds, residential real estate, unincorporated businesses, and human capital) that are not included in the value weighted NYSE stock index, taxes and skewness preference.

The version of the CAPM that should be employed in estimating a public utility's cost of equity capital cannot be conclusively demonstrated by theoretical arguments. A positive theory of the valuation of risking assets should not be judged upon the realism of its assumptions but rather on the accuracy of its predictions. The relationship between risk premiums and betas that is used to estimate the cost of equity capital should therefore be estimated econometrically rather than specified *a priori.*

Section 2 compares the predictions of alternative versions of the CAPM. The assertion that risk premiums are proportional to NYSE betas is shown to result in a downward (upward) biased prediction of the cost of equity capital for a public utility having a NYSE beta that is less (greater) than unity, a dividend yield higher (lower) than the yield on the value weighted NYSE stock index, and/or a systematic skewness that exceeds (is less than) its beta.

Section 3 discusses problems that arise in implementing CAPM approaches and presents possible solutions. Section 4 describes econometric procedures for

* Stanford University, Columbia University, and Bell Laboratories and Columbia University, respectively.

estimating the relationship between risk premiums and NYSE betas. Section 5 presents estimates of CAPM parameters, and, Section 6, using two utilities as examples, illustrates how these estimates can be used to measure the cost of equity capital.

II. Alternative versions of the CAPM: Theory and Evidence

The versions of the CAPM discussed below all assume that investors are risk averse and have homogeneous beliefs. They also assume that a riskless asset exists, that all assets are marketable, and that there are no transactions costs or indivisibilities. The mean-variance versions assume that expected utility is completely defined over the first two moments of the rate of return on investors portfolios. The three moment CAPM assumes that investors have utility functions displaying non-increasing absolute risk aversion and that expected utility is defined over the first three moments of the rate of return on investors portfolios. The before-tax versions ignore taxes while the after-tax versions account for the differential taxation of dividends and capital gains. The constrained borrowing versions allow unlimited short selling of risky securities while the unconstrained borrowing versions allow unlimited short selling of the riskless security (i.e., unlimited borrowing).

The Traditional Version of the CAPM

The traditional version of the CAPM developed by Sharpe [1964] and Lintner [1965] predicts the following relationship between risk premiums and betas,

$$E(\tilde{r}_i) = E(\tilde{r}_m)\beta_i, \tag{1}$$

where:

$E(\tilde{r}_i)$ = the risk premium, or expected excess rate of return above the riskless rate of interest, on the i-th security,
$E(\tilde{r}_m)$ = the risk premium on the market portfolio of all assets, and
β_i = $\mathrm{Cov}(\tilde{r}_i, \tilde{r}_m)/\mathrm{Var}(\tilde{r}_m)$, the beta of the i-th security measured against the true market portfolio of all assets.

Before-Tax Constrained Borrowing Versions of the CAPM

Constrained borrowing versions of the CAPM have been developed by Lintner [1969], Vasicek [1971], Black [1972], Brennan [1972], and Fama [1976]. They predict the following relationship between risk premiums and betas,

$$E(\tilde{r}_i) = E(\tilde{r}_m)\beta_i + E(\tilde{r}_z)(1 - \beta_i), \tag{2}$$
$$\text{or} \quad E(\tilde{r}_i) = E(\tilde{r}_z) + \beta_i(E(\tilde{r}_m) - E(\tilde{r}_z)) \tag{2A}$$

where:

$E(\tilde{r}_z)$ = the risk premium on the minimum variance zero beta portfolio.

With diverse investor preferences and no borrowing (Vasicek [1972] and Black

[1972]), divergent borrowing and lending rates (Brennan [1972]), or margin restrictions (Fama [1976]), the risk premium on the zero beta portfolio is positive (i.e., $E(\tilde{r}_z) > 0$). The first term on the RHS of relation (2) is the risk premium on security i that is predicted by the traditional CAPM. The second term is the bias inherent in that prediction when investor borrowing is constrained. Because $E(\tilde{r}_z) > 0$, the traditional CAPM's prediction of the risk premium would be biased downward (upward) for a public utility having a beta less (greater) than unity.

After-Tax Versions of the CAPM

After-tax versions of the CAPM have been developed by Brennan [1973] under the assumption of unlimited borrowing and lending and by Litzenberger and Ramaswamy [1979] under constrained borrowing. They predict the following relationship between risk premiums, betas and dividend yields,

$$E(\tilde{r}_i) = E(\tilde{r}_m)\beta_i + E(\tilde{r}'_z)(1 - \beta_i) + E(\tilde{r}_h)(d_i - \beta_i d_m), \tag{3}$$

where:

$E(\tilde{r}'_z)$ = the risk premium on a portfolio having a zero beta and zero dividend yield,
$E(\tilde{r}_h)$ = the expected rate of return on a hedge portfolio having a zero beta and a dividend yield of unity,
d_i = the dividend yield on stock i, and
d_m = the dividend yield on the market portfolio.

The first term on the RHS of relation (3) is once again the prediction of the traditional CAPM. The sum of the second and third terms indicates the bias inherent in this prediction. With constrained borrowing, the sign of $E(\tilde{r}'_z)$ cannot be determined theoretically; however, econometric estimates indicate that $E(\tilde{r}'_z) > 0$. This result implies that the second term on the RHS of relation (3) is positive (negative) for public utilities having betas less (greater) than unity. With the taxation of corporate dividends and the preferential taxation of capital gains, $E(\tilde{r}_h) > 0$. Therefore, the third term on the RHS of relation (3) would be positive (negative) for a public utility having a beta less (greater) than unity and a dividend yield that is higher (lower) than the dividend yield on the market portfolio. Thus, the sum of the second and third terms is positive (negative) for public utilities having betas less (greater) than unity and higher (lower) than average dividend yields, indicating that the prediction of the traditional version of the CAPM would be downward (upward) biased.

The Three Moment Version of the CAPM

The three moment CAPM, developed by Rubinstein [1973] and Kraus and Litzenberger [1976], predicts the following relationship between risk premiums, betas, and gammas (systematic skewness),

$$E(\tilde{r}_i) = E(\tilde{r}_m)\beta_i + E(\tilde{r}_w)(\gamma_i - \beta_i), \tag{4}$$

where:

$$\gamma_i = \frac{E[(\tilde{r}_i - E(r_i))(\tilde{r}_m - E(r_m))^2]}{E[(\tilde{r}_m - E(\tilde{r}_m))^3]}, \text{ the systematic skewness of security } i$$

$E(\tilde{r}_w)$ = the expected risk premium on a security having a zero beta and a gamma of unity.

With non-increasing absolute risk aversion, $E(\tilde{r}_w) > 0$. The second term on the RHS of relation (4) is the bias inherent in the traditional version of the CAPM. For a public utility whose future profitability is constrained by the regulatory process, gamma may be less than beta and, the risk premium predicted by the traditional version of the CAPM may be downward biased.

Missing Asset Version of the CAPM

Many classes of assets such as human capital, residential real estate, unincorporated business, and bonds are not included in the value weighted index of NYSE stocks. This "missing assets" problem has been analyzed by Mayers [1972], Sharpe [1977] and Roll [1977]. If the traditional version of the CAPM were valid (i.e., if risk premiums were proportional to true betas) it can be shown that,[1]

$$E(\tilde{r}_i) = E(\tilde{r}_s)\beta_{i,s} + E(\tilde{r}_{zs})(1 - \beta_{i,s}) + u_i \tag{5}$$

where:

$$u_i = E(\tilde{r}_m)\beta_{e_i,zs} - E(\tilde{r}_{zs})\{\beta_{i,zs} - (1 - \beta_{i,s})\}$$

and:

$\beta_{i,s}$ = the beta of security i w.r.t. the NYSE index,
$E(\tilde{r}_{zs})$ = the risk premium on the minimum variance zero NYSE beta portfolio,

[1] To obtain relation (5) note that without loss of generality the return on any security i may be expressed as,

$$\tilde{r}_i - E(\tilde{r}_i) = \beta_{i,s}[\tilde{r}_s - E(r_s)] + \beta_{i,zs}[\tilde{r}_{zs} - E(\tilde{r}_{zs})] + \tilde{e}_i$$

where:

$$E(e_i) = \text{Cov}(e_i, r_s) = \text{Cov}(e_i, r_{zs}) = 0$$

Multiplying both sides by $\tilde{r}_m$, taking expectations and dividing by the variance of $\tilde{r}_m$ yields.

$$\beta_i = \beta_{i,s}\beta_s + \beta_{i,zs}\beta_{zs} + \beta_{e_i},$$

where z is used here to refer to the zero beta portfolio related to NYSE index.
Substituting the RHS of the above relation for β_i in relation (1) yields

$$E(\tilde{r}_i) = [E(\tilde{r}_m)\beta_s]\beta_{i,s} + [E(r_m)\beta_{zs}]\beta_{i,zs} + E(r_m)\beta_{e_i}$$

Using the traditional CAPM to evaluate the terms in $[\cdot]$'s yields

$$E(\tilde{r}_i) = E(\tilde{r}_s)\beta_{i,s} + E(r_s)\beta_{i,zs} + E(\tilde{r}_m)\beta_{e_i}$$

which, when rearranged, is relation (5) in text.

$\beta_{e_i,zs}$ = the beta of the residual of security i measured using a two factor model where the factors are the value weighted NYSE index and the minimum variance zero NYSE beta portfolio.

The first term on the RHS of relation (5) is the predicted return on security i obtained by naively assuming that the NYSE portfolio is the true market portfolio. If the NYSE portfolio were on the efficient frontier then the third term, u_i, would be zero for all i and the second term would be the bias inherent in this naive application of the traditional model. Thus, even if the NYSE portfolio were efficient and risk premiums were proportional to true market betas, risk premiums would not in general be proportional to NYSE betas. For example, if the NYSE portfolio was efficient, but riskier than the true market portfolio, there would be an *ex-ante* linear relationship between risk premiums and NYSE betas with a positive intercept (i.e., $E(\tilde{r}_i) = E(\tilde{r}_{zs}) + \beta_{i,s}(E(\tilde{r}_s) - E(\tilde{r}_{zs})))$.

However, there is no reason to believe that the NYSE portfolio is on the efficient frontier. Here the error term on the RHS of relation (5) would no longer be identically zero for all securities. However, the value weighted average of the error term on the RHS of relation (5) is zero.[2] Thus, for a randomly selected NYSE stock (i) where its probability of selection is proportional to its weight in the NYSE index, the expectation of u_i would be zero. Thus, when the NYSE portfolio is not efficient, *ex-ante* risk premiums would be linear functions of NYSE betas plus an error term. If the minimum variance zero-NYSE beta portfolio had a positive beta with respect to the true market, then its risk premium would be positive (i.e., $E(\tilde{r}_{zs} > 0)$). This would imply the existence of a (non-proportional) linear relationship between risk premiums and NYSE betas (with a positive intercept) plus an error term.

Other Versions of the CAPM

Other versions of the CAPM have been developed. Merton [1971], Cox, Ingersoll and Ross [1978], Breeden and Litzenberger [1978] and Breeden [1980] have derived intertemporal CAPM's that account for shifts in the investment opportunity set. The Merton and the Cox, Ingersoll and Ross studies present multi-beta equilibrium models. The Breeden and Litzenberger, and the Breeden studies, respectively, indicate that the relevant measure of risk is covariance with the marginal utility of consumption and a beta measured relative to aggregate consumption.

While the CAPM theories previously discussed were developed in terms of a single good model, they have been implemented using nominal rates of return. Gonzalez-Gaverra [1973] developed a model that accounts for unanticipated inflation. It suggests that *nominal* risk premiums are linearly related to *real* betas rather than nominal betas.

[2] This follows because for the value weighted index of NYSE stocks $\beta_{es,zs} = \beta_{sz} = (1 - \beta_{ss}) = 0$ by construction.

Implications of Empirical Evidence

Empirical studies by Black, Jensen and Scholes [1972], Fama and MacBeth [1973] and Friend and Blume [1973] find that the relationship between average excess rates of return and NYSE betas is linear, with a positive intercept, rather than proportional. There are at least three possible explanations for these results:

1. Constraints on investor borrowing;
2. Misspecification caused by the exclusion of classes of assets such as bonds, residential real estate, unincorporated business, and human capital from the index; and/or,
3. Misspecification caused by exclusion of other independent variables such as systematic skewness and/or dividend yield from the model.

Each of these explanations yields predictions that are inconsistent with the proportional relationship between risk premiums and NYSE betas that has been asserted in several recent rate cases that use CAPM. To the extent that the NYSE index is a good surrogate for the true market index, the first explanation suggests that a linear relationship between NYSE betas and risk premiums should be estimated and used to calculate the cost of equity capital. The second explanation suggests that a broadly based index should be used to calculate betas. Unfortunately, rate of return data do not exist for some classes of assets and are difficult to obtain for other classes of assets. This suggests that an exact linear relationship between risk premiums and NYSE betas does not exist. However, the NYSE betas of common stocks may be highly correlated with the true unknown betas (measured relative to the true market index). This suggests that the empirical relationship between risk premiums and NYSE betas should be estimated empirically rather than asserted *a priori.*

The third explanation suggests that the effect of other independent variables on risk premiums should be estimated and used in calculating the cost of equity capital. Empirical studies by Rosenberg and Marathé [1979], Litzenberger and Ramaswamy, and Blume [1979] find that, in addition to beta, dividend yield has a significant positive association with average excess rates of return. This result is consistent with the after-tax version of the CAPM and suggests that the relationship between risk premiums, NYSE betas, and dividend yields should be estimated and used to calculate the cost of equity capital. However, Litzenberger and Ramaswamy also present preliminary evidence indicating that the relationship between risk premiums, NYSE betas and yields is non-linear. This result is inconsistent with the Brennan, and Litzenberger and Ramaswamy versions of after-tax CAPM and therefore the use of a linear relationship between risk premiums, betas and dividend yield to calculate the cost of equity capital should be viewed as an approximation to a more complex non-linear relationship.

An empirical study by Kraus and Litzenberger [1976] found that, in addition to beta, systematic skewness (gamma) has a significant negative association with average excess rates of return. However, estimates of gamma are not stable over time and therefore it is not possible to obtain accurate *ex-ante* estimates of the systematic skewness of individual securities. Betas and gammas have a strong positive association, and, therefore, the use of a linear relationship between risk premiums and betas may again be viewed as approximation to a more complex relationship.

III. Implementing the CAPM Approach

This section discusses econometric problems that are associated with implementing the CAPM approach and presents possible solutions.

Measuring Expectations

The alternative versions of the CAPM discussed above are positive theories of the relationship between *ex-ante* risk premiums and betas.

Ex-ante risk premiums are not, however, directly observable. To handle this problem it is assumed that investors have rational expectations, that the excess rate of return (realized rate of return less the riskless rate of interest) on any portfolio or security in a given month is an unbiased estimate of its risk premium, and that the excess rates of return on each portfolio are independently and identically distributed over time.

Computing Beta

Estimates of the unadjusted betas for each security are obtained from an OLS regression of its excess rate of return on the value weighted NYSE index over a 60 month period. An advantage of using monthly data is that it mitigates the effect of the nonsimultaneity of closing prices. Recently Scholes and Williams [1978] have suggested the use of lagged rates of return as an instrumental variable for the errors in variables problem. Unfortunately, the CRSP daily data file is not available over a sufficiently long time period to be useful in estimating the parameters of the relationship between risk premiums and NYSE betas. Beaver, Kettler and Scholes [1970] and Rosenberg and McKibben [1973] have shown that accounting measures of risk are useful in predicting future betas. However, the Compustat data file, which would be necessary to estimate betas using either of their procedures, does not cover the 1926 to 1947 period.

It has been observed by Blume [1971] that historical betas which are adjusted towards unity are better predictors of future betas (in a mean square forecast error sense) than are unadjusted betas. One explanation of this phenomenon is that the true underlying betas follow a mean reverting process where the mean is unity. Another is that the true underlying beta is constant, the historical beta is a sample estimate of the true underlying beta, and the prior of the beta is unity. These explanations are not mutually exclusive and Blume [1975] has presented preliminary empirical evidence that the true underlying betas display reversion towards the population mean of unity.

Regardless of the cause of the phenomenon, the existence of reversion towards unity suggests that "adjusted" betas, computed as convex combinations of the historical beta and unity, are better predictors than are unadjusted betas. A possible approach is to assume that the same weight ω, $(0 < \omega < 1)$ is applicable to all securities such that,

$$\beta_i(\text{predicted}) = \omega\beta_{i(\text{historical})} + (1 - \omega)1.$$

This is the procedure used by Blume [1971] and by Merrill Lynch and is called a global adjustment approach. This approach implies a linear relationship between future betas and historical betas and suggests that unadjusted betas may be used to predict risk premiums. For example, consider the following relationship between excess rates of returns and globally adjusted betas,

$$\tilde{r}_i = a + b[\omega\beta_{i(\text{historical})} + (1 - \omega)1] + \tilde{e}_i.$$

This relationship reduces to the following relationship between excess rates of return and historical betas,

$$\tilde{r}_i = a' + b'\beta_{i(\text{historical})} + \tilde{e}_i$$

where

$$a' = a + b(1 - \omega), \quad \text{and}$$

$$b' = b\omega.$$

Note that for predictive purposes, a' and b' may be estimated directly; knowledge of ω is not required. If the ω used were constant over time, then the cost of equity capital estimates obtained using CAPM parameters measured using this global procedure would be identical to those obtained using unadjusted betas. This global adjustment procedure has the advantage of not depending on the exact cause or combination of causes for the empirical tendency of beta estimates to revert towards unity.

Another approach to adjusting betas is to use an individual Bayesian-adjustment procedure. This approach recognizes that the variances of sample betas (obtained from an OLS time series regression of stock returns on the NYSE index) are not identical. This approach is, however, based on the assumption that the true underlying beta is stationary which is inconsistent with Blume's preliminary empirical evidence. Under this approach, the probability of selecting a given stock is assumed to be proportional to its weight in the value weighted portfolio. Therefore, the diffuse prior estimate of its beta is unity. The variance of this prior is computed as

$$\text{Var}(\beta_{i,\text{prior}}) = \textstyle\sum_{i=1}^{N_t} [[V_i / \sum_{i=1}^{N_t} V_i](\beta_{i,\text{sample}} - 1.0)^2] \tag{6}$$

where V_i is the value of firm i. Thus, the variance of the prior is the cross-sectional variation in sample betas around the value weighted mean of unity. It differs from the Vasicek [1971] adjustment, which computes the prior variance as,

$$\text{Var}(\beta_{i,\text{prior}}) = \textstyle\sum_{i=1}^{N} (\beta_{i,\text{sample}} - 1.0)^2 / N$$

thus giving equal weight to each security. With either the global adjustment or the individual adjustment, the posterior estimate of beta has variance given by

$$\mathrm{Var}(\beta_{i,\text{prior}}) = \omega_i \,\mathrm{Var}(\beta_{i,\text{sample}}) + (1 - \omega_i)^2 \,\mathrm{Var}(\beta_{i,\text{prior}}) \tag{7}$$

This information is useful in estimating the model coefficients.

Knowing the variance of the measurement error allows implementation of the classical approach to errors in variables and therefore yields a consistent estimator of $\hat{a}_2 = [E(\tilde{R}_{zs}) - R_f]$ (see the next section).

Computing the Risk-Free Rate

In choosing the appropriate proxy for the riskless rate of interest, explicit cognizance should be taken of the fact that the fair rate of return determined in a rate case is applicable throughout a future period. Therefore, the risk-free rate that is chosen should correspond to a risk free return that would be expected to prevail during the period that the pending rate order is expected to be in force.

One simple procedure is to compute the risk free rate as a simple average of monthly forward Treasury Bill rates for the period the pending rate order is expected to be in effect. The Treasury-Bill futures market or McCulloch's [1971] procedure of computing forward rates from the yield curve can be used to obtain the needed forward rates.

Data

The raw data for this study consisted of monthly rates of returns for all NYSE securities and monthly measures of the risk-free rate of interest.

Monthly data on security returns are obtained from the Center for Research in Security Prices (CRSP) at the University of Chicago. The same service also provides the return on a value weighted index of all the NYSE stocks.

Monthly returns on high grade commercial paper from 1926 to 1951 were used as a proxy for the return on a riskless asset. From 1952 to 1978, the return on a Treasury Bill with 30 days to maturity was used for this purpose.

IV. Estimating the Relationship between Risk Premiums and NYSE Betas

The structural econometric model that is estimated in a given cross section is,[3]

$$\tilde{r}_{it} = a + b\beta_{ist} + \tilde{e}_{it}.$$

Any linear estimator of this relationship is obviously a linear combination of the dependent variable. Since the dependent variable is a rate of return, any linear estimator is a rate of return on a portfolio. The unbiasedness condition for an estimator is a set of constraints on this portfolio that assures that the expected rate of return on the portfolio is the coefficient that we are estimating. Once a set

[3] Procedures specific to the implementation of the three moment CAPM, the multiperiod CAPM, and the unanticipated inflation CAPM are not discussed because of unresolved issues relating to the estimation or *ex-ante* systematic skewness, *ex-ante* consumption betas and real betas. The after-tax version of the CAPM and its refinements are considered in Litzenberger and Ramaswamy (1979, 1980).

of portfolio weights $\{h_{it}, i = 1, 2, \cdots, N_t\}$ is chosen, the resulting portfolio rate of return is,

$$\sum_{i=1}^{N_t} h_{it} r_{it} = a \sum_{i=1}^{N_t} h_{it} + b[\sum_{i=1}^{N_t} h_{it}\beta_{ist}] + \sum_{i=1}^{N_t} h_{it} e_{it}. \tag{8}$$

The unbiasedness condition for an estimator of $(a + b)$ requires the following portfolio constraints,

$$\sum_{i=1}^{N_t} h_{it} = 1, \quad \text{and} \quad \sum_{i=1}^{N_t} h_{it}\beta_{ist} = 1.$$

That is, for any normal portfolio (i.e. portfolio weights summing to unity) having a beta of unity, equation (8) reduces to,

$$\sum_{i=1}^{N_t} h_{it} r_{it} = a + b + \sum_{i=1}^{N_t} h_{it} e_{it}.$$

Since the $E(\tilde{e}_{it}) = 0$, $\forall$ i, it follows that such a portfolio is an unbiased estimator. The best linear unbiased estimator of $a + b$ would be the rate of return on the minimum variance normal portfolio having a beta of unity.

Without loss of generality the variance of any portfolio having a NYSE beta of unity may be expressed as

$$\text{Var}[\sum_{i=1}^{N_t} h_{it}\tilde{r}_{it}] = \text{Var}(\tilde{r}_{st}) + \text{Var}[\sum_{i=1}^{N_t} h_{it}\tilde{e}_{it}],$$

where:

$\tilde{r}_{st}$ = the excess rate of return on the value weighted NYSE portfolio

Note that $\text{Var}(\sum_{i=1} h_{it}\tilde{e}_{it}) = 0$ if and only if the h_{it} for each security corresponds to its weight in the NYSE value weighted index. Thus, the *best* unbiased estimator of $a_t + b_t$ is the excess rate of return on the value weighted NYSE portfolio itself, r_{st}. Assuming that observations of r_{st} are i.i.d., the BLUE estimation of $a + b$ is the average over time of the excess rate of return on the NYSE portfolio.

The unbiasedness conditions for a linear estimator of 'a' are,

$$\sum_{i=1}^{N_t} h_{it} = 1 \quad \text{and} \quad \sum_{i}^{N_t} h_{it}\beta_{ist} = 0.$$

Thus, the rate of return on any normal portfolio that has a zero (true) NYSE beta is an unbiased estimator of 'a'. In any cross-sectional month the best linear unbiased estimator of 'a' would be the rate of return on the minimum variance zero NYSE beta portfolio, r_{zst}.

Without loss of generality the variance of any portfolio having a zero NYSE beta may be expressed as

$$\text{Var}(\sum_{i}^{N_t} h_{it}\tilde{r}_{it}) = \text{Var}(\sum_{i}^{N_t} h_{it}e_{it})$$

Assume momentarily that the true NYSE betas are known. Using the single index model, which assumes that $\text{Cov}(e_{it}, e_{jt}) = 0$ $\forall$ $i, j \neq i$, the variance of a normal portfolio having a zero NYSE beta is,

$$\text{Var}(\sum_{i=1}^{N_t} h_{it} r_{it}) = \sum_{i=1}^{N_t} h_{it}^2 S_{it}^2$$

where:

S_{it}^2 = the residual risk for security i.

The BLUE estimator of 'a' for a given cross-section month 'a_t' is, therefore, the minimum variance rate of return zero NYSE beta portfolio. The rate of return on this portfolio in month t may be obtained by solving the above described portfolio problem for the h_{it}'s and then calculating $\sum_{i=1}^{N_t} h_{it} r_{it}$. The resulting r_{zst} is

$$r_{zst} = \left[m_{pp} - \frac{m_{p\beta}^2}{m_{\beta\beta}} \right]^{-1} \cdot \left[m_{pr} - \frac{m_{p\beta} m_{\beta r}}{m_{\beta\beta}} \right] \tag{10}$$

where:

$$m_{pp} = \frac{1}{N_t} \sum_{i=1}^{N_t} \frac{1}{S_{it}^2} \qquad m_{p\beta} = \frac{1}{N_t} \sum_{i=1}^{N_t} \frac{\beta_{it}}{S_{it}^2} \qquad m_{pr} = \frac{1}{N_t} \sum_{i=1}^{N_t} \frac{r_{it}}{S_{it}^2}$$

$$m_{\beta\beta} = \frac{1}{N_t} \sum_{i=1}^{N_t} \frac{\beta_{it}^2}{S_{it}^2} \qquad m_{\beta r} = \frac{1}{N_t} \sum_{i=1}^{N_t} \frac{r_{it}\beta_{it}}{S_{it}^2}$$

In the absence of measurement errors in betas, if r_{zst}'s were i.i.d. then a simple average of this would yield the BLUE estimator of 'a', the risk premium on the minimum variance NYSE portfolio.

Errors in the Measurement of Betas

The true NYSE betas are unobservable. If the previously described procedures were used with estimated betas, the cross sectional variance in the estimated betas $m_{\hat{\beta}\hat{\beta}}$ would be an upward biased and inconsistent estimator of the cross sectional variance in the true betas. This would give h_{it}'s that results in portfolio that has positive true NYSE beta for large samples and hence an upward biased estimator of 'a' the risk premium on a portfolio having a zero NYSE beta. To obtain a consistent estimator of 'a', a classical errors in variables approach is undertaken. In this approach, the 'normal' equations for estimation are adjusted as follows: The cross sectional variation in the true NYSE betas, that are unobserved, is replaced by the cross sectional variation in observed NYSE betas less the (sum) of the variances of the measurement errors of the NYSE betas, which has been computed above as $\mathrm{Var}(\hat{\beta}_{it})$. When solved, the resulting estimator is,

$$r_{zt} = \left[m_{pp} - \frac{m_{p\hat{\beta}}^2}{m_{\hat{\beta}\hat{\beta}} - Q} \right]^{-1} \cdot \left[m_{pr} - \frac{m_{p\hat{\beta}} m_{\hat{\beta} r}}{m_{\hat{\beta}\hat{\beta}} - Q} \right] \tag{11}$$

where

$$Q = \frac{1}{N_t} \sum_{i=1}^{N_t} \frac{\mathrm{Var}(\hat{\beta}_{it})}{\hat{S}_{it}^2}.$$

Comparing relation (10) with relation (11) indicates that they are identical except for the Q term which is the adjustment due to the variability in the estimator of beta. Under the assumption that the error term is normally distributed and that the true variances of the measurement errors are known, $m_{\hat{\beta}\hat{\beta}} - Q$ is the maximum likelihood estimator of $m_{\beta\beta}$, the cross sectional variation in the unobservable tru NYSE betas. It also follows that $m_{p\hat{\beta}}$ and $m_{\hat{\beta}r}$ are maximum likelihood estimator of $m_{p\beta}$ and $m_{\beta r}$. Since the above described estimator of 'a' is a function of a maximum likelihood estimator, it is also a maximum likelihood estimator (se Kendall and Stuart [1973]).

V. Estimates of CAPM Parameters

The consistent estimators (as described in the previous section) of the parameter of the relationship between *ex-ante* premiums and NYSE betas are given i Table 1. Results for individually Bayesian adjusted and raw betas are presented

Since the raw betas are not adjusted towards unity, the a_t's calculated eac month would be expected to have a positive beta. Regressing the a_t's that wer calculated using raw NYSE betas on the r_{st}'s gives a slope coefficient of 0.109 an an R^2 of 0.039. This suggests that the true NYSE beta on this portfolio is positive

The standard deviation of the r_{zt}'s is less than the standard deviation of th $(r_{st} - r_{zt})$'s as the mathematics of the efficient frontier would suggest. Sinc individually Bayesian adjusted betas are adjusted towards unity, the r_{zt}'s calcu lated using the Bayesian adjusted betas would be expected to have a zero NYS beta. However, regressing the r_{zt}'s that were calculated using Bayesian adjuste NYSE betas (the r_{zt}'s) on the r_{st}'s gives a slope of -0.144 and an R^2 of 0.0327 This suggests that the NYSE beta of this portfolio is negative. Unfortunately, a econometric rationale for a negative beta is not readily apparent. Again th standard deviation of the r_{zt}'s is lower than the standard deviation of the $(r_{st} - r_{zt})$'s as would be expected from the mathematics of the efficient frontier. The $\bar{r}$ calculated using Bayesian adjusted betas is lower than the $\bar{r}_z$ calculated usin raw betas as would be expected given the correlation of these portfolios with th NYSE index. Note that the consistent estimators of 'a' and a' reported in TABL 1 are lower than the corresponding inconsistent estimators obtained using gen-

Table 1

CAPM Parameters

Bayesian Betas

$$r_{it} = r_{zst} + [r_{st} - r_{zst}]\beta_{is(\mathrm{ADJ})} + \epsilon_{it}$$

$$\hat{a} = \bar{r}_{rs} = 0.136 \qquad \hat{b} = \bar{r}_s - \bar{r}_{zs} = 0.519$$

$$\sigma(r_{zst}) = 4.73 \qquad \sigma(r_{st} - r_{zst}) = 8.14$$

Raw Betas

$$r_{it} = [r_{zst} + (r_{st} - r_{zst})(1 - \omega)] + [(r_{st} - r_{zst})\omega]\beta_{is(\mathrm{raw})} + \epsilon_{it}$$

$$\hat{a}' = 0.326, \qquad \hat{b}'_t = 0.330$$

$$\sigma(a_t) = 3.23 \qquad \sigma(b_t) = 6.14$$

where

$$a'_t = [r_{zst} + (r_{st} - r_{zst})(1 - \omega)], \qquad b'_t = [(r_{st} - r_{zst})\omega]$$

eralized least squares as would be expected from the econometric theory. GLS parameters are reported in TABLE 2.

VI. Examples and Conclusions

To illustrate the biases that arise by naively assuming a proportional relationship between NYSE betas and risk premiums, the parameters from Table 1 along with estimates of the risk free rate of interest and betas were used to estimate the cost of equity capital for two utilities: one with a beta substantially less than unity, Pacific Gas and Electric (PGE), and one with a beta close to unity, Consolidated Edison (Con Ed).

The relevant unadjusted and Bayesians betas are presented in Table 3 along with cost of equity capital estimates made by naively assuming a proportional relationship, and by using the estimated linear relationship in all of the calculations.

A risk free rate of interest of 9.29% per annum was used. This was obtained by averaging forward interest rates implied by Treasury Bill futures settlement prices on the International Monetary Market for October 1, 1979 (the assumed date of the rate case). Assuming a nine month lag between the rate case and its implementation, Treasury Bill futures contracts for delivery in June 1980 and thereafter were used in the average. For the main model the same estimates of the risk premium on the NYSE index was used (i.e., $a + b$). The monthly cost of equity capital estimates were compounded to obtain annual estimates.

The differences in the cost of equity capital estimates, which illustrate the so called "zero beta effect", are substantial for PG&E since its NYSE beta estimates are less than unity. The zero beta effect is negligible for Con Ed since its beta is close to unity.

Table 2

Bayesian Betas		
	$\hat{a} = 0.321$	$\hat{b} = 0.335$
	$\sigma(\hat{a}_t) = 3.26$	$\sigma(\hat{b}_t) = 6.23$
Raw Betas		
	$\hat{a} = 0.420$	$\hat{b}' = 0.236$
	$\sigma(\hat{a}'_t) = 3.04$	$\sigma(\hat{b}_t) = 5.19$

Table 3

Maximum Likelihood Estimates of the Cost of Equal Capital

	Unadjusted/Global adjusted betas			Individually Adjusted Bayesian betas		
Company	Raw beta	Proportional	Linear	Beta	Proportional	Linear
PGE	0.48	13.49	15.78	0.53	13.87	14.74
Con Ed	1.06	18.68	18.42	1.05	18.61	18.50

These two companies, as well as utilities in general, have residual standard deviations that are smaller than those of most industrial firms. Hence the individual Bayesian adjustment procedure did not adjust the betas of the sample companies as much towards unity as a global procedure would have. The effect of the individual Bayesian adjustment procedure on the estimated parameters presented in Table 2 can be loosely viewed as reflecting the average adjustment towards unity. Therefore, for a utility such as PG&E having a NYSE beta less than unity and having a lower than average residual risk and the cost of capital estimates obtained using a linear relationship between risk premiums and betas estimated with individually adjusted Bayesian betas would be lower than that obtained using a linear relationship estimated with unadjusted or globally adjusted betas. The difference between the estimates obtained using the individually Bayesian adjusted estimates and the raw betas is negligible for Con Ed since its beta is close to unity. The difference between the estimates for PG&E are substantial and indicate the importance of future research on the revision of betas towards unity.

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DISCUSSION

RICHARD S. BOWER*: As a regulator I find the three papers stimulating and helpful. Each is reassuring because it supports some aspect of regulatory practice, rewarding because it suggests an opportunity to improve practice and less than totally satisfying because it does not provide all the answers.

Bruce Greenwald's paper on admissable rate bases may be too rich to digest at a single sitting. Greenwald starts conventionally by stating that the Hope decision criteria for fairness to investors and capital attraction are met by any rate base valuation formula which permits market value to equal rate base and which causes rate base to increase dollar for dollar with new investment. He then argues, less conventionally, that to be admissable a formula must allow regulators to establish cash revenue requirements and rate base appreciation through time and

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Energy Studies Review Vol. 18, No. 2, 2011

COST OF EQUITY FOR ENERGY UTILITIES: BEYOND THE CAPM

STÉPHANE CHRÉTIEN & FRANK COGGINS

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.

JEL Classifications: G12, L51, L95, K23

Keywords: Cost of Capital, Rate of Returns, Energy Utilities

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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.

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[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]

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[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

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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

[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

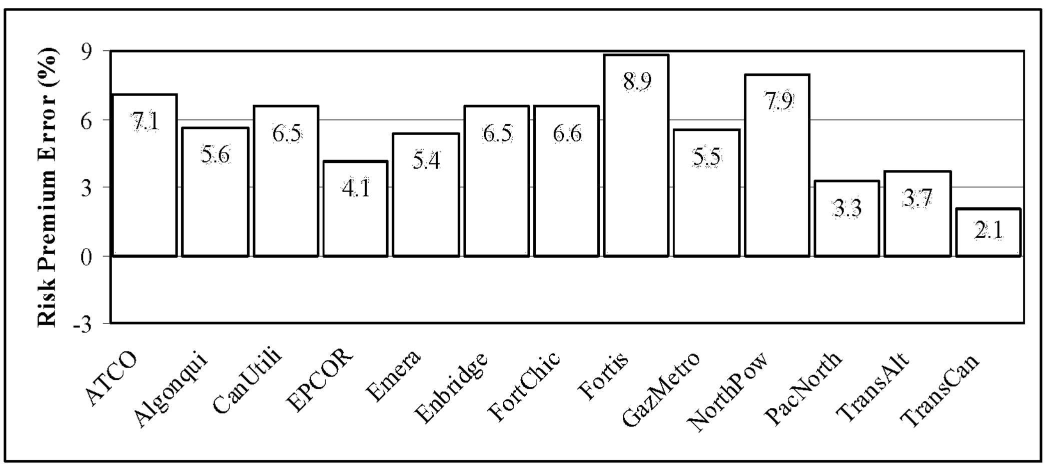


Figure 1b: Firms in the USindex Portfolio

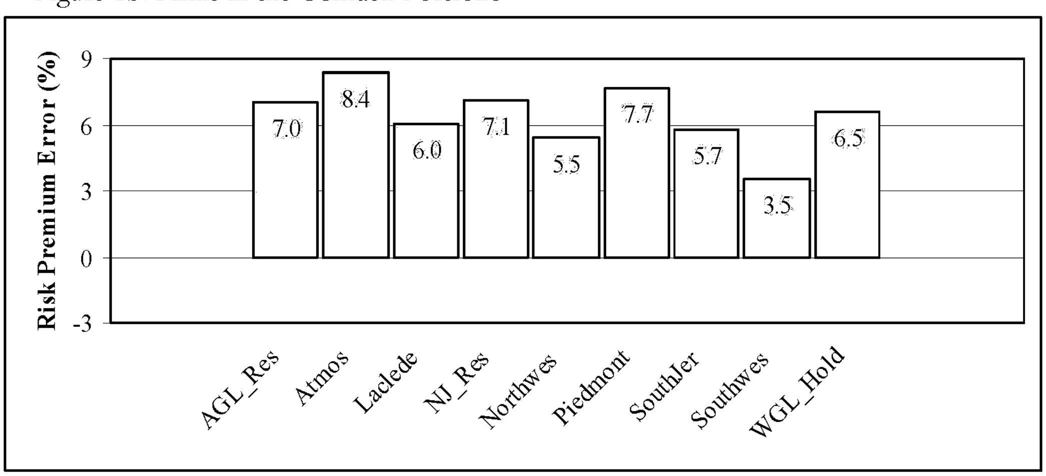
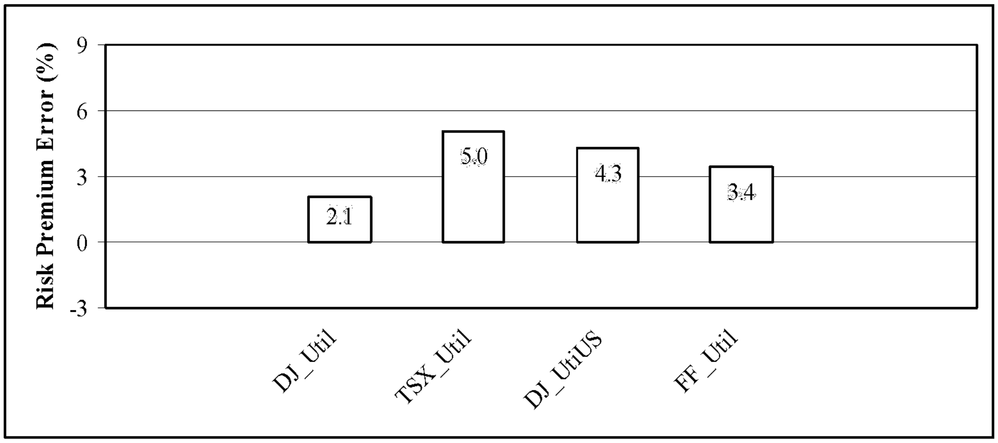


Figure 1c: Utilities Reference Portfolios



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

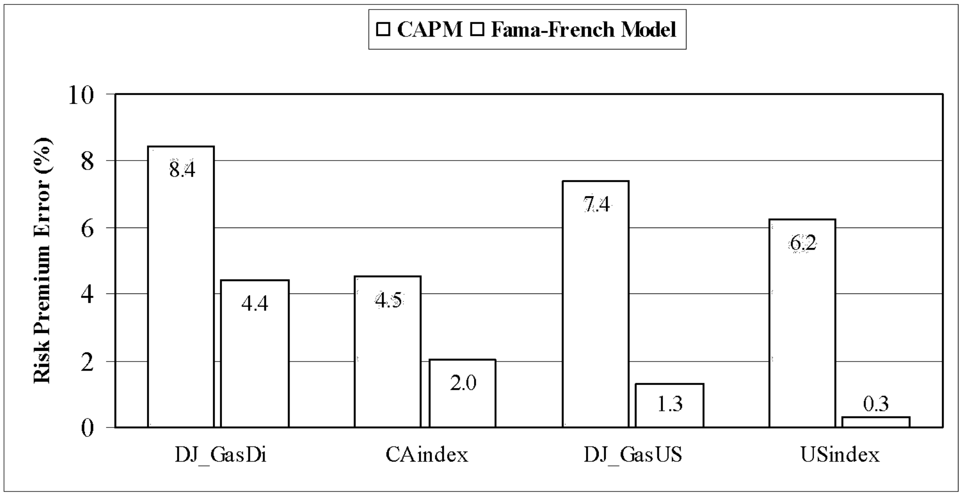
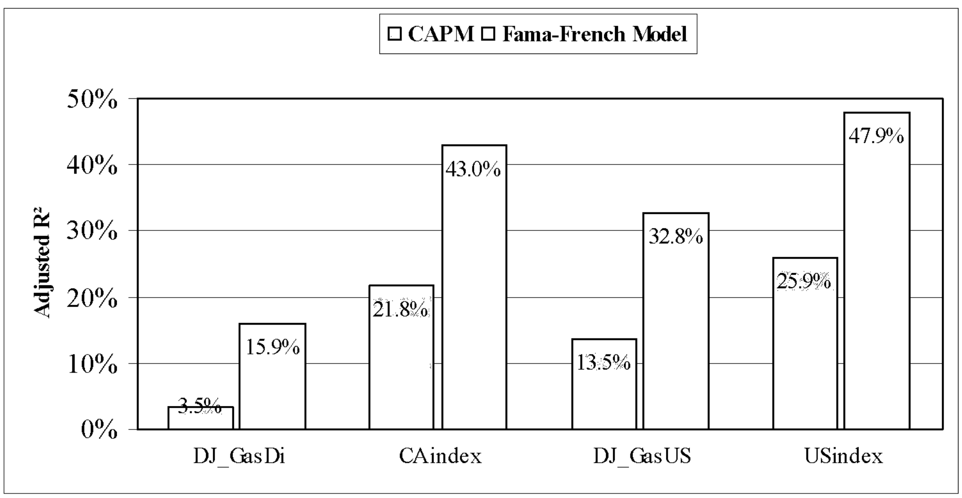


Figure 2b: Adjusted R^2s



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

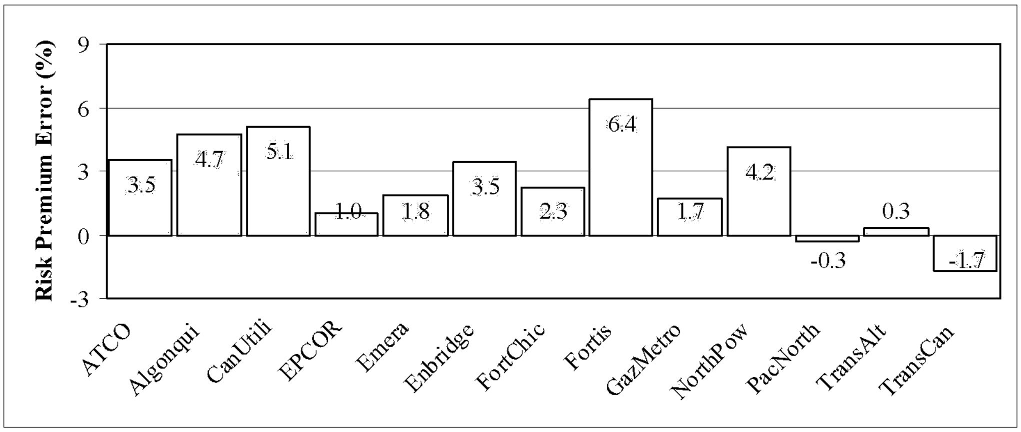


Figure 3b: Firms in the USindex Portfolio

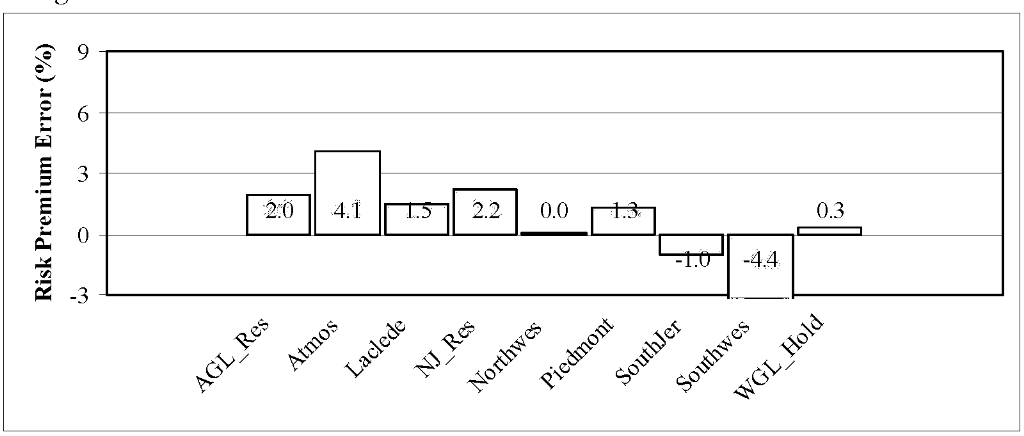
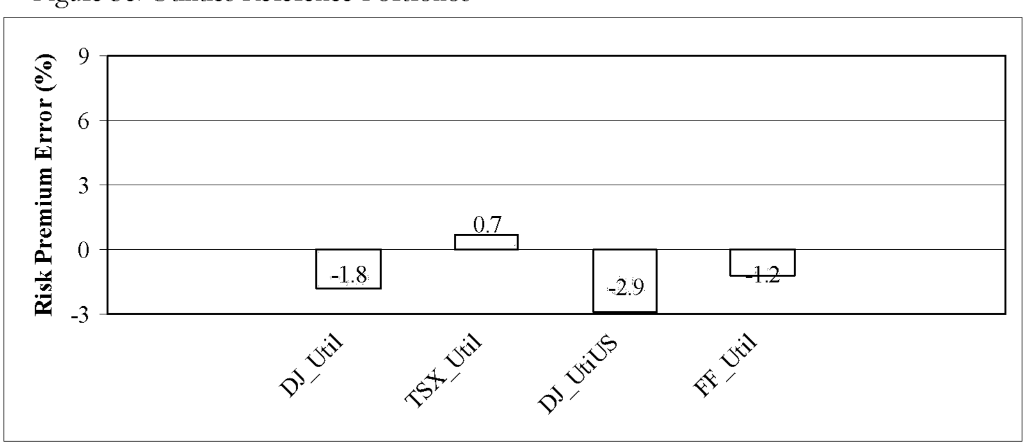


Figure 3c: Utilities Reference Portfolios



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

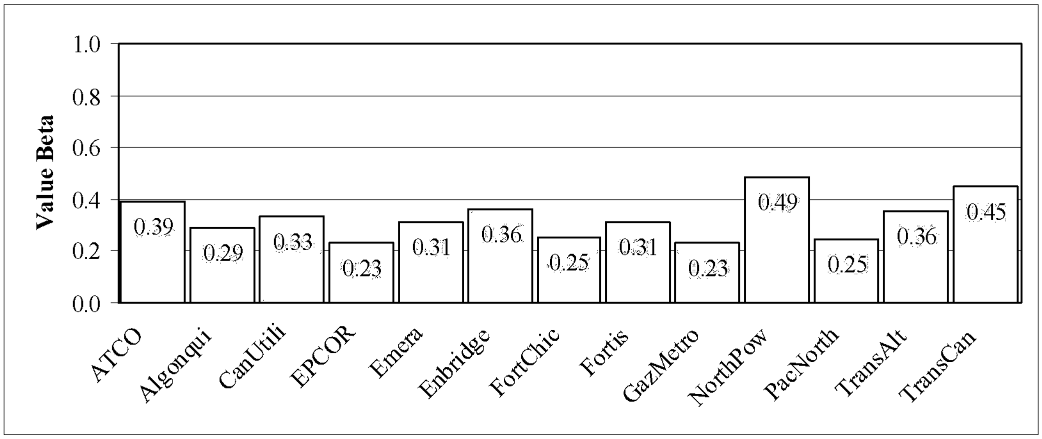


Figure 4b: Firms in the USindex Portfolio

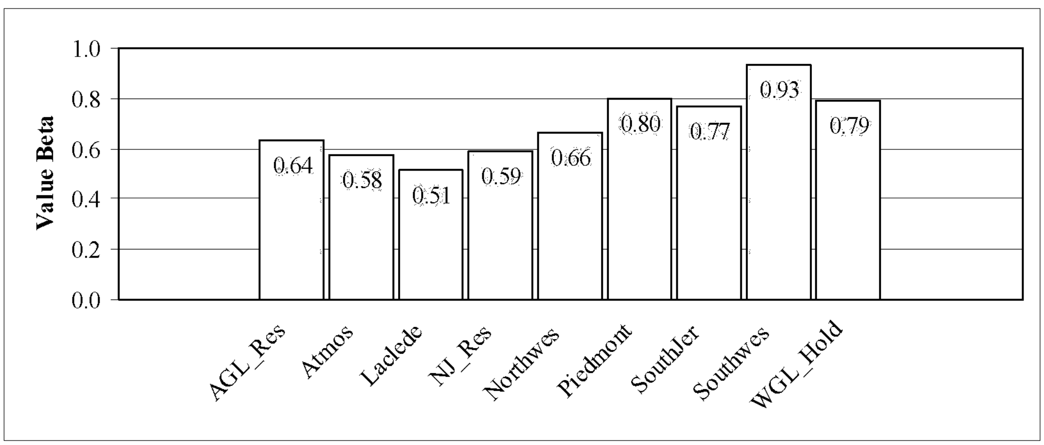
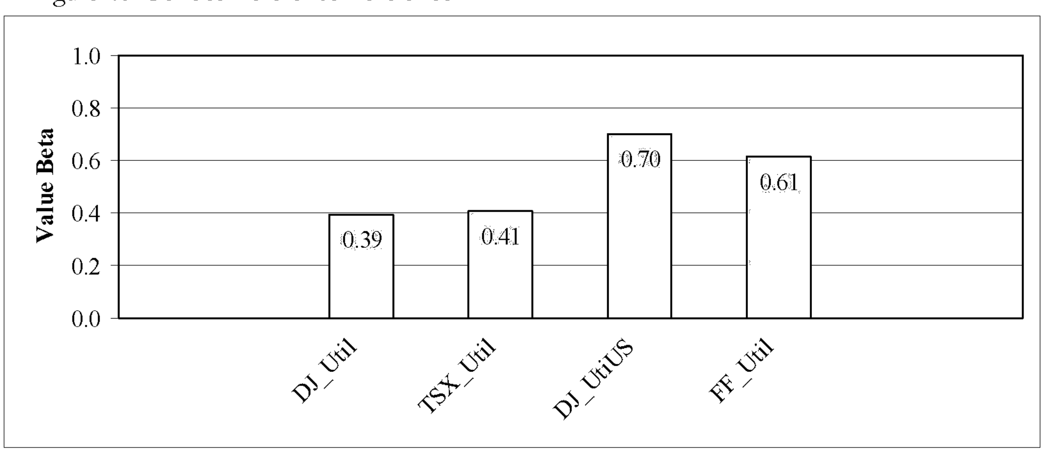


Figure 4c: Utilities Reference Portfolios



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

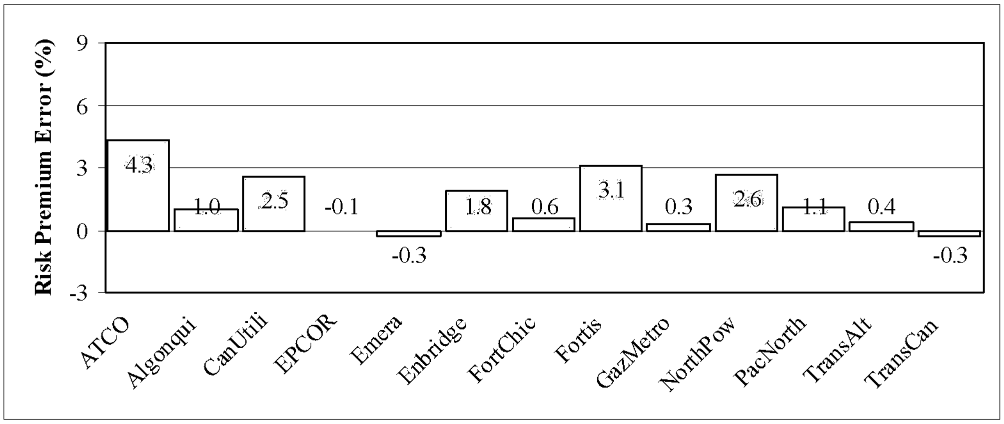


Figure 5b: Firms in the USindex Portfolio

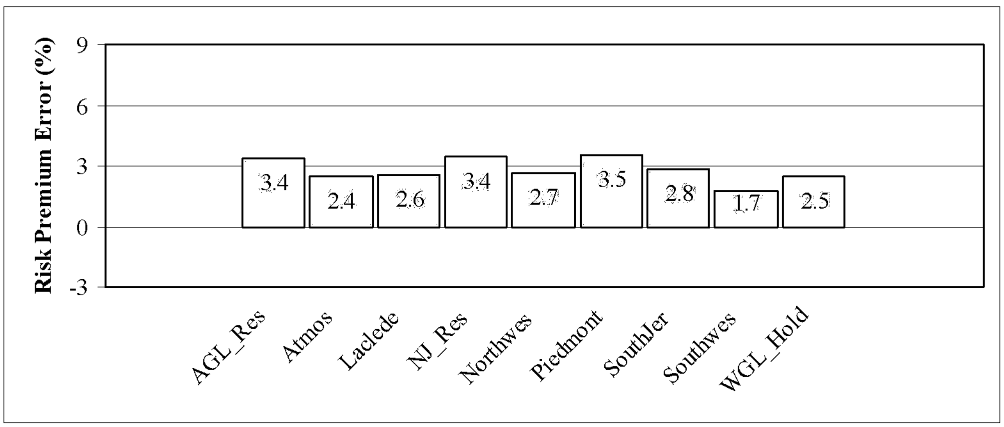
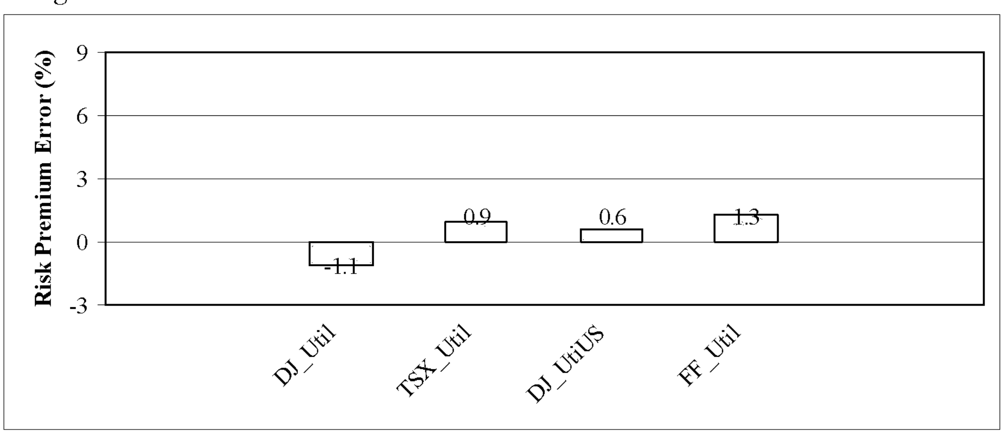


Figure 5c: Utilities Reference Portfolios



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.

ACKNOWLEDGEMENTS

We would like to thank Mark Lowenstein and Jacques St-Pierre for helpful discussions. We gratefully acknowledge financial support from the *Institut de Finance Mathématique de Montréal*, the Investors Group Chair in Financial Planning (Chrétien), the Faculty of Business Administration at Laval University (Chrétien) and the *Faculté d'administration, Université de Sherbrooke* (Coggins). Stéphane Chrétien is also grateful to Kalok Chan (Department Head) and the Department of Finance at the Hong Kong University of Science and Technology, where part of this research was conducted while he was a Visiting Associate Professor of Finance.

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SOAH DOCKET NO. 473-21-2606
DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

CONFIDENTIALITY STATEMENT UNDER SECTION 4 OF THE PROTECTIVE ORDER

The undersigned attorney for El Paso Electric Company (EPE) submits this statement under the section 4 of the Protective Order entered in this case. Materials provided in the responses to the following questions in the Texas Industrial Energy Consumers' first set of discovery are exempt from public disclosure pursuant to sections 552.101 and 552.110 of the Public Information Act.

RFI	Attachment	Designation
TIEC 1-2	Attachment 1	Confidential
TIEC 1-2	Attachment 2	Confidential
TIEC 1-4	Attachment 1	Confidential
TIEC 1-4	Attachment 2	Confidential
TIEC 1-4	Attachment 3	Confidential
TIEC 1-5	Attachment 1	HSPM
TIEC 1-5	Attachment 2	HSPM
TIEC 1-5	Attachment 3	HSPM
TIEC 1-5	Attachment 4	HSPM
TIEC 1-5	Attachment 5	HSPM
TIEC 1-5	Attachment 6	HSPM
TIEC 1-6	Attachment 5	Confidential
TIEC 1-6	Attachment 6	Confidential
TIEC 1-6	Attachment 7	Confidential
TIEC 1-6	Attachment 8	Confidential
TIEC 1-6	Attachment 9	Confidential
TIEC 1-6	Attachment 10	Confidential
TIEC 1-6	Attachment 11	Confidential
TIEC 1-6	Attachment 12	Confidential
TIEC 1-6	Attachment 13	Confidential
TIEC 1-6	Attachment 14	Confidential
TIEC 1-6	Attachment 15	Confidential
TIEC 1-6	Attachment 16	Confidential
TIEC 1-6	Attachment 17	Confidential

RFI	Attachment	Designation
TIEC 1-6	Attachment 18	Confidential
TIEC 1-6	Attachment 19	Confidential
TIEC 1-6	Attachment 20	Confidential
TIEC 1-6	Attachment 22	Confidential
TIEC 1-6	Attachment 23	Confidential
TIEC 1-6	Attachment 24	Confidential
TIEC 1-6	Attachment 25	Confidential
TIEC 1-6	Attachment 26	Confidential
TIEC 1-6	Attachment 27	Confidential
TIEC 1-6	Attachment 28	Confidential
TIEC 1-6	Attachment 29	Confidential
TIEC 1-6	Attachment 30	Confidential
TIEC 1-6	Attachment 33	Confidential
TIEC 1-6	Attachment 35	Confidential
TIEC 1-7	Attachment 1	Confidential
TIEC 1-10	Attachment 2	Confidential
TIEC 1-13	Attachment 1	Confidential
TIEC 1-13	Attachment 3	Confidential

Some of the information contained in the documents concern business operations that are commercially sensitive and not otherwise readily available to the public and that if released could cause substantial competitive harm to EPE. Additionally, some of the material provided contains documents that are subject to confidentiality provisions that require EPE to prevent the public release of the information contained therein. The undersigned counsel for EPE has reviewed the information described above sufficiently to state in good faith that the information is exempt from disclosure under the PIA and merits the confidential designation given to it.

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CERTIFICATE OF SERVICE

I certify that a true and correct copy of this document was served by email on all parties of record on August 9, 2021.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

DOCKET NO. E-7, SUB 1146 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 819 In the Matter of Amended Application by Duke Energy Carolinas, LLC, for Approval of Decision to Incur Nuclear Generation Project Development Costs DOCKET NO. E-2, SUB 1152 In the Matter of Petition of Duke Energy Carolinas, LLC, for an Order Approving a Job Retention Rider DOCKET NO. E-7, SUB 1110 In the Matter of Joint Application by Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for Accounting Order to Defer Environmental Compliance Costs	ORDER ACCEPTING STIPULATION, DECIDING CONTESTED ISSUES, AND REQUIRING REVENUE REDUCTION

HEARD: Tuesday, January 16, 2018, at 7:00 p.m., in the Macon County Courthouse, Courtroom A, 5 W. Main Street, Franklin, North Carolina

Wednesday, January 24, 2018, at 7:00 p.m., in the Guilford County Courthouse, Courtroom 1C, 201 S. Eugene Street, Greensboro, North Carolina

Tuesday, January 30, 2018, at 6:30 p.m., in the Mecklenburg County Courthouse, 832 E. 4th Street, Charlotte, North Carolina

Monday, March 5, 2018, at 1:30 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

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BY THE COMMISSION: On July 25, 2017, pursuant to Commission Rule R1-17(a), Duke Energy Carolinas, LLC (DEC or the Company), filed notice of its intent to file a general rate case application. On August 25, 2017, the Company filed its Application to Adjust Retail Rates and Request for an Accounting Order (the Application), along with a Rate Case Information Report, Commission Form E-1 (Form E-1), and the direct testimony and exhibits of David B. Fountain, North Carolina President, DEC; Jane L. McManeus, Director of Rates & Regulatory Planning, DEC; Scott L. Batson, Senior Vice President of Nuclear Operations, Duke Energy Corporation (Duke Energy);[1] Stephen G. De May, Senior Vice President Tax and Treasurer, Duke Energy Business Services,

[1] DEC is a wholly owned subsidiary of Duke Energy Corporation. Tr. Vol. 6, p. 155.

LLC (DEBS);[2] James H. Cowling, Director of Outdoor Lighting for DEC, DEBS; Nils J. Diaz, Managing Director, the ND2 Group, LLC; David L. Doss Jr., Director of Electric Utilities and Infrastructure Accounting, DEBS; Christopher M. Fallon, Vice President, Duke Energy Renewables and Commercial Portfolio (and former Vice President Nuclear Development), Duke Energy; Janice Hager, President, Janice Hager Consulting; Robert B. Hevert, Partner, ScottMadden, Inc.; Retha Hunsicker, Vice President Customer Operations, Customer Information Systems, DEBS; Jon F. Kerin, Vice President Governance and Operations Support, Coal Combustion Products, DEBS; Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC; Kimberly D. McGee, Rates & Regulatory Strategy Manager, DEC and Duke Energy Progress, LLC (DEP); Joseph A. Miller Jr., Vice President of Central Services, DEBS; Robert M. Simpson III, Director Grid Improvement Plan Integration for Duke Energy's Regulated Utilities Operations, DEP; Donald L. Schneider, Jr., General Manager, Advanced Metering Infrastructure (AMI) Program Management, DEBS; and Michael J. Pirro, Manager of Southeast Pricing & Regulatory Solutions, DEC, DEP, and Duke Energy Florida, LLC.

Petitions to intervene were filed by NCSEA on July 26, 2017; CIGFUR III on August 8, 2017; CUCA on August 9, 2017; the Rate-Paying Neighbors on August 23, 2017; EDF on August 25, 2017; NCFB on September 6, 2017; NC WARN on September 7, 2017; Sierra Club on September 18, 2017; Kroger on September 19, 2017; ASU on September 29, 2017; NCLM on October 3, 2017; Piedmont EMC, Rutherford EMC, Haywood EMC, and Blue Ridge EMC on October 16, 2017; the Commercial Group on October 31, 2017; Tech Customers on November 2, 2017; Concord and Kings Mountain on November 17, 2017; NC Justice Center, et al. on December 19, 2017; and Durham on January 3, 2018. Notice of intervention was filed by the Office of the Attorney General (AGO) on August 31, 2017.

The Commission entered orders granting the petitions of NCSEA on August 7, 2017; EDF on September 5, 2017; NC WARN on September 15, 2017; CUCA on September 18, 2017; CIGFUR III, the Rate-Paying Neighbors, and NCFB on September 19, 2017; Sierra Club on September 27, 2017; Kroger on September 28, 2017; NCLM on October 4, 2017; ASU on October 19, 2017; Piedmont EMC, Rutherford EMC, Haywood EMC, and Blue Ridge EMC on October 20, 2017; the Commercial Group and Tech Customers on November 8, 2017; Concord and Kings Mountain on December 14, 2017; and Durham and NC Justice Center, et al. on January 11, 2018. The AGO's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20. The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19.

On September 19, 2017, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On October 13, 2017, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice, and on October 20,

[2] DEBS provides various administrative and other services to DEC and other affiliated companies of Duke Energy. Tr. Vol. 4, p. 33.

2017, the Commission issued an Amended Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice. On November 3, 2017, Sierra Club filed a Motion to Schedule Additional Public Hearing. On December 22, 2017, the Commission entered an Order Denying Sierra Club's Request for Public Hearing. On January 30, 2018, and February 23, 2018, the Commission issued orders revising the schedule for the expert witness hearing.

On July 10, 2017, the Commission issued an order consolidating DEC's request for deferral of coal ash costs in Docket No. E-7, Sub 1110 with this rate case. On October 18, 2017, the Commission issued an order consolidating the general rate proceeding in Docket No. E-7, Sub 1146 with DEC's request to implement a job retention rider in Docket No. E-7, Sub 1152 and DEC's petition for approval to cancel the William States Lee III Nuclear Station (Lee Nuclear Project or Lee Nuclear) in Docket No. E-7, Sub 819.

DEC filed the supplemental testimony and exhibits of Company witness McManeus on December 15, 2017, and the second supplemental testimony and exhibits of Company witness McManeus on January 16, 2018.

On January 18, 2018, the AGO filed a motion for extension of time for intervenors to file testimony and exhibits. On January 20, 2018, the Commission entered an order granting an extension of time for intervenors to file testimony and exhibits until January 23, 2018, and for DEC to file rebuttal testimony and exhibits until February 6, 2018. On January 18, 2018, EDF filed the direct testimony of Paul J. Alvarez, President, Wired Group. On January 23, 2018, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Engineer with the Electric Division of the Public Staff; L. Bernard Garrett, Secretary/Treasurer, Garrett and Moore, Inc.; John R. Hinton, Director of the Economic Research Division of the Public Staff; Michelle M. Boswell, Staff Accountant with the Accounting Division of the Public Staff; Charles Junis, Engineer with the Water, Sewer, and Communications Division of the Public Staff; Jay Lucas, Engineer with the Electric Division of the Public Staff; Michael C. Maness, Director of the Accounting Division of the Public Staff; Roxie McCullar, Consultant, William Dunkel and Associates; James S. McLawhorn, Director of Electric Division of the Public Staff; Dustin Ray Metz, Engineer with the Electric Division of the Public Staff; Vance F. Moore, President, Garrett and Moore, Inc.; David C. Parcell, Principal and Senior Economist, Technical Associates, Inc.; Scott J. Saillor, Engineer with the Electric Division of the Public Staff; and Tommy C. Williamson, Jr., Engineer with the Electric Division of the Public Staff. On January 23, 2018, the AGO filed the direct testimony and exhibits of J. Randall Woolridge, Professor of Finance, Pennsylvania State University, and Dan J. Wittliff, Managing Director of Environmental Services, GDS Associates, Inc.

On January 23, 2017, CUCA filed the direct testimony and exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; the Tech Customers filed the direct testimony and exhibits of Kurt G. Strunk, Director of National Economic Research Associates (NERA), and Edward D. Kee, Expert Affiliate, NERA Economic Consulting;

Kroger filed the direct testimony and exhibits of Kevin C. Higgins, Principal, Energy Strategies, LLC; NC Justice Center, et al. filed the direct testimony and exhibits of Satana Deberry, Executive Director, North Carolina Housing Coalition, John Howat, Senior Policy Analyst, National Consumer Law Center, and Jonathan F. Wallach, Vice President, Resource Insight, Inc.; Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, Ph.D., Consultant, Ezra Hausman Consulting, and Mark Quarles, Principal Scientist and Owner, Global Environmental, LLC; NCLM filed the direct testimony and exhibits of Brian W. Coughlan, President, Utility Management Services, Inc., F. Hardin Watkins, Jr., City Manager, City of Burlington, Maria S. Hunnicutt, General Manager, Broad River Water Authority, and Adam Fischer, Transportation Director, City of Greensboro; CIGFUR III filed the direct testimony and exhibits of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and NCSEA filed the direct testimony and exhibits of Justin R. Barnes, Director of Research, EQ Research LLC, Caroline Golin, Southeast Regulatory Director, Vote Solar, and Michael E. Murray, President, Mission:data Coalition. On January 24, 2018, the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy Strategy and Analysis, Wal-Mart Stores, Inc. and Wayne Rosa, Energy and Maintenance Manager, Food Lion, LLC.

On January 25, 2018, DEC filed a motion to strike the direct testimony of NCSEA witness Murray. On February 1, 2018, NCSEA filed its response in opposition to DEC's motion to strike the testimony of witness Murray. The Commission issued an order on February 6, 2018, denying DEC's motion to strike the testimony of witness Murray.

On January 26, 2018, DEC filed a motion to strike the direct testimony of EDF witness Alvarez and a motion to strike the direct testimony of NC Justice Center, et al. witness Howat. On January 30, 2018, EDF filed its response in opposition to DEC's motion to strike the testimony of witness Alvarez. On February 2, 2018, NC Justice Center, et al. filed its response in opposition to DEC's motion to strike the testimony of witness Howat. On February 6, 2018, the Commission issued an order denying DEC's motion to strike the testimony of witness Alvarez and an order granting DEC's motion to strike the testimony of witness Howat. The Commission struck from the record NC Justice Center, et al. witness Howat's direct testimony from page 4, line 21, to page 5, line 7, from page 21, line 3, to page 32, line 5, and page 32, lines 9 to 19.

On February 6, 2018, DEC filed the rebuttal testimony and exhibits of Company witnesses: McManeus; Cowling; De May; Diaz; Doss; Fallon; Fountain; Hager; Hevert; Hunsicker; Kerin; Jeffrey T. Kopp, Manager, Burns & McDonnell Engineering Company, Inc.; McGee; Miller; Pirro; Schneider; Thomas Silinski, Vice President, Total Rewards and Human Resource Operations, DEBS; Simpson; John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants, LLC; James Wells, Vice President, Environmental Health and Safety, Coal Combustion Products, DEBS; and Wright.

On February 20, 2018, the Public Staff filed supplemental testimony and exhibits of witnesses Boswell, Hinton, Junis, Maness, Moore, and Saillor. The Public Staff filed the second supplemental testimony and exhibits of witnesses Hinton and Boswell on

March 19, 2018. On March 9, 2018, the AGO filed the supplemental testimony of witness Woolridge. On March 20, 2018, the Tech Customers filed the supplemental testimony of Dr. Sharon Brown-Hruska, Managing Director, NERA, and witness Strunk.

On February 28, 2018, DEC and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement (the Stipulation). The Stipulation resolves some of the issues between the two parties in this docket. However, several unresolved issues still exist, including but not limited to: (1) the treatment of the Company's coal combustion residuals costs; (2) the amount of the Basic Facilities Charge (BFC); (3) whether it is appropriate to allow a return on the unamortized balance related to the Company's Lee Nuclear plant during the amortization period; (4) the status of the Company's Nuclear Decommissioning Trust Fund (NDTF) and the Public Staff's proposal to adjust nuclear decommissioning expense; (5) the manner in which the Federal Tax Cuts and Jobs Act (Tax Act) should be addressed in this case; (6) whether the Grid Reliability and Resiliency Rider (Grid Rider) should be adopted in this proceeding, and if so, which costs would be included in the Grid Rider and the structure of a Grid Rider; and (7) two discrete issues related to the Company's proposal for a Jobs Retention Rider (JRR), further described herein (collectively, the Unresolved Issues).

On March 1, 2018, the Public Staff filed settlement supporting testimony and exhibits of witnesses Boswell, Maness, and Parcell, and DEC filed settlement supporting testimony and exhibits of witnesses De May, Fountain, Hevert, McManeus, and Pirro. On February 28, 2018, DEC entered into and filed a Partial Settlement Agreement with NCLM, Concord, and Kings Mountain related to street lighting issues. On March 2, 2018, DEC entered into and filed an Amended Partial Settlement Agreement with NCLM, Concord, Kings Mountain, and Durham, which modified the original settlement related to certain street lighting issues and added Durham as a party (the Lighting Settlement).

The three public witness hearings were held as scheduled. The following public witnesses appeared and testified:

Franklin: David Watters, Selma Sparks, The Honorable Kevin Corbin, Donn Erickson, Henry Horton, Fred Crawford, Virginia Bugash, Avram Friedman, Debra Lawley, Bob Boyd, Tamara Zwinak, Margaret Crownover, Janet Wilde, and Robert Smith

Greensboro: Sharon Goodson, John Carter, Aaron Martin, Clarence Wright, Ruth Martin, Deborah Graham, Hester Petty, David Sevier, Joan Bass, John Merrell, Marta Concepcion, Gayle Tuch, August Preschle, Claudia Lange, Harry Phillips, Rexanne Bishop, Tim Stevenson, Taina Diaz-Reyes, Debbie Smith, Doug Ruder, Gladys Ellison, John Robins, Henry Fansler, Rachel Kriegsman, David Freeman, John Motsinger, Lib Hutchby, and Megan Longstreet

Charlotte: Brian Kasher, Mary Anne Hitt, Yvette Baker, Melvina Williams, Lilly Taylor, Steve English, Nancy Nicholson, Sally Kneidel, Callina Satterfield, Amy Brown, Roger Hollis, Kent Crawford, Ritchie Johnson, Ernie McLaney, Willie Dawson, Pat Moore, Beth Henry, James Sprouse, Charles Talley, June Blotnick, Charles King, Meg Houlihan, Steve Copulsky, Elaine Jones, Christian Cano, Joel Segal, Kathy Sparrow, Rick Lauer, Nicholas Rose, Wells Eddleman, Walker Spruill, Violet Mitchell, and Holliday Adams

The matter came on for expert witness testimony on March 5, 2018. DEC presented the testimony of witnesses De May, Hevert, Fountain, McManeus, Spanos, Kopp, Fallon, Diaz, Doss, Wright, Kerin, Simpson, Hunsicker, Schneider, Pirro, Hager, and Wells. The Public Staff presented the testimony of witnesses McLawhorn, Moore, Garrett, Maness, Williamson, Hinton, Metz, and Floyd. The AGO presented the testimony of witnesses Woolridge and Wittliff. The Sierra Club presented the testimony of witness Quarles. NCSEA presented the testimony of witnesses Golin and Barnes. CUCA presented the testimony of witness O'Donnell. NCLM presented the testimony of witness Coughlan. Tech Customers presented the testimony of witness Kee. The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand.

DEC filed various late-filed exhibits and responses to Commission requests on the following dates: March 28, 2018, March 29, 2018, April 2, 2018, April 3, 2018, April 4, 2018, April 5, 2018, April 6, 2018, April 19, 2018 and April 23, 2018.

On April 16, 2018, the AGO filed a Response to Commission Request and Motion to Admit AGO Late-Filed Exhibit, which was granted on April 24, 2018.

The parties submitted briefs and/or proposed orders on April 27, 2018.

On June 1, 2018, DEC filed a Stipulation and Settlement Agreement between DEC and the EDF, Sierra Club, and NCSEA and a Stipulation and Settlement Agreement between DEC and the Commercial Group relating to the Power Forward Carolinas program and the Grid Rider proposed by DEC in this case (collectively, the Grid Rider Settlement). In its cover letter transmitting the stipulations and settlement agreements, DEC indicated that in order to mitigate the impact of a rate adjustment on low income customers and to support job training, DEC will make a shareholder-funded contribution totaling $4 million to the following programs: $1.5 million to the Helping Home Fund program for income qualified customers, $1.5 million to the Share the Warmth energy assistance fund, and $1 million to the Duke Energy/Piedmont Natural Gas Community College Apprenticeship Grant Program.

Between June 1, 2018, and June15, 2018, the following parties filed opposition and/or concerns regarding the Grid Rider Settlement: NC Justice Center, NC WARN, Public Staff, CUCA, AGO, CIGFUR III, and Tech Customers.

On June 8, 2018, the North Carolina Clean Energy Business Alliance (NCCEBA) filed a Petition to Intervene which was denied as out-of-time on June 20, 2018.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, the Lighting Settlement, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. DEC is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in the central and western portions of North Carolina and western South Carolina. DEC is a wholly-owned subsidiary of Duke Energy, and its office and principal place of business is located in Charlotte, North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DEC, under Chapter 62 of the General Statutes of North Carolina.

3. DEC is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2016, adjusted for certain known changes in revenue, expenses, and rate base through December 31, 2017, and the costs for the W. S. Lee Combined Cycle (Lee CC) updated through February 28, 2018.

The Application

5. DEC, by its Application and initial direct testimony and exhibits, originally sought a net increase of approximately $611 million, or 12.8%, in its annual electric sales revenues from its North Carolina retail electric operations, including a rate of return on common equity of 10.75% and a capital structure consisting of 47% debt and 53% equity. The Company also requested a Grid Rider to recover an additional $35.2 million, which has the effect of an additional 0.8% increase. DEC filed supplemental filings and testimony after its initial Application and the effect of the Company's supplemental filings was to change its proposed annual revenue requirement increase to $700,645,000.

6. DEC submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2016, adjusted for certain known changes in revenue, expenses, and rate base.

The Stipulation

7. On February 28, 2018, DEC and the Public Staff (the Stipulating Parties) entered into and filed the Stipulation resolving some of the issues in this proceeding between the two parties. Those issues that were not resolved by the Stipulation are referred to herein as the "Unresolved Issues."

8. The revenue requirement effect of the Stipulation is shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected[3] and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues,[4] which provide sufficient support for the annual revenue required on the issues agreed to in the Stipulation.

9. The Stipulation is the product of the give-and-take in settlement negotiations between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, along with other evidence from the Company and intervenor parties, and along with statements from customers of the Company as well as testimony of public witnesses concerning the Company's Application.

10. The Stipulation resolves only some of the disputed issues between the Stipulating Parties. The Unresolved Issues include the cost recovery of the Company's CCR costs, the recovery amortization period and return during the amortization period, allocation issues associated with CCR costs, the amount of ongoing CCR costs to be included in rates, or whether certain CCR costs are recoverable under N.C. Gen. Stat. § 62-133.2. Further Unresolved Issues include amount of project development costs to be recovered for the Lee Nuclear Plant and whether the unamortized balance should earn a return, whether the Nuclear Decommissioning Trust Fund is overfunded, the amount of the Basic Facilities Charge, Power Forward and the Grid Rider, the methodology for calculating customer usage, recovery of costs for AMI, issues surrounding the implementation of the Federal Tax Cuts and Jobs Act (the Tax Act), several issues related to the JRR, and the proper contingency factor related to depreciation. The Unresolved Issues are resolved by the Commission and are addressed later in this Order.

[3] On April 19, 2018, the Public Staff filed Boswell Third Supplemental and Stipulation Exhibit 1 Corrected, which: (1) corrects the Lee CC addition to plant in service; (2) corrects the Lee CC deferral calculation; (3) updates the Grid Rider amount; and (d) reflects the Company's position on each filed issue.

[4] On April 19, 2018, the Company filed Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues and Revised McManeus Workpapers – Updated for Post-Hearing Issues, which reflect the following updates: (1) updates to the salaries and wages adjustment to reflect the Company and Public Staff's resolution on how to quantify the agreement reached in the Stipulation; (2) updates to the Lee CC plant and expense related items to reflect final costing information for inclusion in this proceeding, including updates to plant investment, related deferred income taxes, depreciation, materials and supplies, and the deferral of those costs between the plant's operation date and the date rates are expected to become effective; and (3) updates to reflect the cash working capital amounts and income taxes that are affected by the adjustments made to salaries and wages, and Lee CC.

Capital Structure, Cost of Capital, and Overall Rate of Return

11. The Stipulating Parties agree that the revenue requirement approved in this Order is intended to provide DEC, through sound management, the opportunity to earn an overall rate of return of 7.35%. This overall rate of return is derived from applying an embedded cost of debt of 4.59% and a rate of return on equity of 9.9% to a capital structure consisting of 48% long-term debt and 52% members' equity. The Stipulation is material evidence entitled to appropriate weight in determining DEC's overall rate of return, cost of debt, rate of return on equity, and capital structure.

12. A 9.9% rate of return on equity for DEC is just and reasonable in this general rate case.

13. A 52% equity and 48% debt ratio is a reasonable capital structure for DEC in this case.

14. A 4.59% cost of debt for DEC is reasonable for the purposes of this case.

15. Notwithstanding the decrease in rates ordered herein, the rates approved in this case, which includes the approved rate of return on equity and capital structure, will be difficult for some of DEC's customers to pay, in particular DEC's low-income customers.

16. Continuous safe, adequate, and reliable electric service by DEC is essential to the support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment.

17. The rate of return on equity and capital structure approved by the Commission appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment with the difficulties that some of DEC's customers will experience in paying the Company's rates.

18. The 9.9% rate of return on equity and the 52% equity financing approved by the Commission in this case result in a cost of capital that is as low as reasonably possible. They appropriately balance DEC's need to obtain equity financing and to maintain a strong credit rating with its customers' need to pay the lowest possible rates.

19. The authorized levels of overall rate of return and rate of return on equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C. Gen. Stat. § 62-133, and are fair to DEC's customers generally and in light of the impact of changing economic conditions.

Adjustments to Cost of Service

20. The agreed-upon accounting adjustments outlined in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues are just and reasonable to all parties in light of all the evidence presented.

State EDIT

21. The Stipulation provides that the state excess deferred income taxes (State EDIT) the Company collected pursuant to the Commission's May 13, 2014 Order in Docket No. M-100, Sub 138 should be returned to customers through a levelized rider that will expire at the end of a four-year period. The Stipulating Parties provide that the appropriate level of State EDIT to be refunded to customers is $60,102,000 annually for the four years following the effective date of the rates approved in this proceeding. The four-year State EDIT rider as set forth in Section III.B of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Customer Connect

22. The Stipulation provides for the removal of the Company's incremental operating expenses for the Customer Connect project as recommended by the Public Staff. In accordance with Section III.C of the Stipulation, the Company is authorized to establish a regulatory asset to defer and amortize expenses associated with the Customer Connect project. As set forth in the Stipulation, the Company is allowed to accrue and recover Allowance for Funds Used During Construction (AFUDC) on the regulatory asset until the DEC Core Meter-to-Cash release (Releases 5-8) of the Customer Connect project goes into service or January 1, 2023, whichever is sooner, at which time a 15-year amortization shall begin. The parties agreed in the Stipulation that in order to provide the Commission and other interested parties with information concerning the status of development, spending, and the accomplishments to date, the Stipulating Parties will develop the reporting format and the content of that report within 90 days of this Order, with the reports to be filed in this docket for the next five years by December 31 of each year or until Customer Connect is fully implemented, whichever is later. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented. However, in order to allow sufficient time for the Company to complete its financial close process for the fiscal year, a critical step in obtaining the financial data needed to accurately report annual spend on Customer Connect, the Commission finds that the annual report required shall be filed by February 15, for the next five years.

Lee Combined Cycle

23. At the time the Stipulation was filed on February 28, 2018, the Company's Lee CC plant was almost complete, but not anticipated to come online until March 2018. Pursuant to the Stipulation, DEC withdrew its adjustment to include incremental operation

and maintenance (O&M) expenses for the Lee CC, and the Public Staff withdrew its displacement adjustment for the Lee CC; the Stipulating Parties therefore agreed that the appropriate level of ongoing O&M expense to be included in rates is $0. The Stipulating Parties further agreed that the appropriate amortization period for the deferred expenses is four years. The Stipulation additionally requires that the Company provide the Public Staff and the Commission with the final cost amounts to be included in this proceeding for determining the impact of the Lee CC on the overall revenue adjustment approved by the Commission by March 23, 2018. The Stipulation provides that the Public Staff utilize these amounts to work with the Company to file with the Commission, on or before April 6, 2018, the Stipulating Parties' final recommendation with regard to the Lee CC-related revenue requirement, including Lee CC deferred costs, using the methodology recommended by the Public Staff in this proceeding, excluding the appropriate amortization period for Lee CC deferred costs. The Stipulating Parties further agreed that it would be appropriate to hold the record open until April 22, 2018, for the sole purpose of allowing the Company to file an affidavit indicating that the plant has closed to service for operational and accounting purposes and that it is used and useful for the benefit of customers. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented.

24. In accordance with Section III.L of the Stipulation, on March 23, 2018, DEC provided the Public Staff and the Commission with the final cost amounts to be included in this proceeding for determining the impact of the Lee CC on the overall revenue adjustment approved by the Commission. On April 10, 2018, the Public Staff filed its updated recommendations regarding Lee CC plant and expense-related items, as shown in Boswell Third Supplemental and Stipulation Exhibit 1. Also on April 10, 2018, the Company filed the Affidavit of Joseph A. Miller, Jr., indicating that as of April 5, 2018, the Lee CC plant closed to service for operational and accounting purposes. On April 19, 2018, DEC filed Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, which, among other things, reflects updates to the Lee CC plant and expense-related items to reflect final cost information for inclusion in this proceeding, including updates to plant investment, related deferred income taxes, depreciation, materials and supplies, and the deferral of those costs between the plant's operation date and the date rates are expected to become effective. Also on April 19, 2018, the Public Staff filed Boswell Third Supplemental and Stipulation Exhibit 1 Corrected, which, among other things, corrects the Lee CC addition to plant in service and corrects the Lee CC deferral calculation. The Lee CC-related revenue requirement updated in the final recommendation of the Stipulating Parties, as shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues is just and reasonable.

Requested Coal Combustion Residuals (CCR) Fuel Costs

25. Given the Commission's Findings of Fact Nos. 57-59 and associated conclusions in its Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase entered on February 23, 2018, in Docket No. E-2, Sub 1142 (2018 DEP Rate Order), in Section III.P of the Stipulation DEC withdrew its request to recover

certain coal combustion residuals (CCR) costs through the fuel adjustment clause related to the excavation and movement of CCRs from the Riverbend Plant in Gaston County, North Carolina to the Brickhaven facility in Chatham County, North Carolina. The Stipulation also provides that the recovery of these costs be left in the Company's deferred CCR balance for consideration of recovery in the Company's base rates. These costs should be excluded from recovery through the fuel adjustment clause, and should be included in the Company's deferred CCR balance for consideration of recovery in the Company's base rates. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented.

Base Fuel Factor

26. Section IV.B of the Stipulation provides that the base fuel and fuel-related cost factors, by customer class, will be as set forth in the following table (amounts are cents per kilowatt-hour (kWh), excluding regulatory fee):

	Residential	General Service/Lighting	Industrial
Total Base Fuel (matches approved fuel rate effective September 1, 2017 in Docket No. E-7, Sub 1129)	1.7828	1.9163	2.0207

The base fuel and fuel-related cost factors set forth in Section IV.B of the Stipulation are just and reasonable to all parties in light of all the evidence presented.

Coal Inventory

27. As set forth in Paragraph III.I. of the Stipulation, DEC shall reduce the amount of coal inventory included in working capital. An increment rider shall be established, effective on the same date as the new base rates approved in this Order, and continuing until inventory levels reach a 35-day supply, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). This rider shall terminate on the earlier of: (a) May 31, 2020, or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in the Stipulation. The reduction to coal inventory included in working capital and the establishment of the increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

28. The Stipulation provides for the use of the Summer Coincident Peak (SCP) methodology for cost allocation between jurisdictions and among customer classes in this case. The Company may continue to use the SCP methodology for allocation between jurisdictions and among customer classes under the provisions of the Stipulation. The

provisions of the Stipulation regarding cost of service methodology are just and reasonable to all parties in light of all the evidence presented.

Lead-Lag Study

29. The Stipulation provides that DEC shall prepare and file a lead-lag study in its next general rate case. This provision of the Stipulation is just and reasonable.

Rate Design

30. Except for the amount of the Basic Facilities Charge which is discussed later in this Order, the Stipulation provides for the implementation of the rate design proposed by Company witness Pirro in his direct testimony, as set out in Section IV.E of the Stipulation. The Stipulating Parties also agreed that, to the extent possible, the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd. Moreover, the Company entered into the Lighting Settlement with NCLM, Concord, Kings Mountain, and Durham, which resolved all outdoor lighting issues raised by intervenors in this docket. Based on all of the evidence presented in this proceeding, the rate design provisions in Section IV.E of the Stipulation and the Lighting Settlement are just and reasonable to all parties in light of all the evidence presented. It is appropriate for the Company to implement the rate design proposed by witnesses Pirro and Cowling, consistent with the provisions in Section IV.E of the Stipulation and the Lighting Settlement.

Vegetation Management, Quality of Service, and Service Regulations

31. DEC's and the Public Staff's agreement relating to vegetation management, as set forth in Section III.A of the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

32. The overall quality of electric service provided by DEC is adequate.

33. The proposed amendments to DEC's Service Regulations are just and reasonable, serve the public interest, and should be approved.

Acceptance of Stipulation

34. The Stipulation and the Lighting Settlement will provide DEC and its retail ratepayers just and reasonable rates when combined with the rate effects of the Commission's decisions regarding the contested issues in this proceeding.

35. The provisions of the Stipulation and the Lighting Settlement are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Stipulation and the Lighting Settlement should be approved in their entirety.

Basic Facilities Charge (BFC)

36. The Company shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES, and ESA) to $14.00. The increase in the BFC for the residential rate class schedules is just and reasonable. The BFC for other rate schedules shall be left unchanged from the current rates.

Customer Usage

37. The methodology for calculating customer usage set forth in the testimony of Public Staff witness Saillor, with the adjustments proposed by Company witness Pirro in his rebuttal testimony, is just and reasonable to all of the parties and should be employed by the Company in this case.

Advanced Metering Infrastructure (AMI)

38. DEC's AMI costs are reasonable and prudent, and DEC should be allowed to recover its AMI costs.

39. DEC should be required to design and propose new rate structures to capture the full benefits of AMI.

40. It is just and reasonable for DEC to recover the remaining book value of its Automated Meter Reading (AMR) meters over 15 years.

Customer Data

41. It is appropriate to address issues regarding access to customer usage data in Docket No. E-100, Sub 147.

Power Forward and the Grid Rider

42. DEC has failed to show that exceptional circumstances exist to justify the establishment of the Grid Rider for recovery of its Power Forward Carolinas (Power Forward) costs.

43. DEC has failed to show at this time that Power Forward costs qualify for deferral accounting treatment.

44. It is not necessary at this time for the Commission to open a separate proceeding to investigate grid modernization programs. For now, DEC should utilize existing proceedings, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission on and collaborate with stakeholders regarding grid modernization initiatives and the potential cost recovery mechanisms for such initiatives.

Lee Nuclear

45. In Docket No. E-7, Sub 819, which has been consolidated with this general rate case, the Company requests Commission approval of its decision to cancel the Lee Nuclear Project pursuant to N.C. Gen. Stat. § 62-110.7(d). The Company requests permission to move the adjusted balance of the Lee Nuclear Project development costs from construction work in progress (CWIP) Account 107 to regulatory asset Account 182.2 and to recover the project development costs in rates by amortizing such costs over a 12-year period. The Company also requests that the unamortized balance of such costs be included in rate base to recover a net-of-tax return on the unamortized balance.

46. DEC's actions in developing the Lee Nuclear Project have been reasonable and prudent and in compliance with the intent of the Commission's orders in Docket No. E-7, Sub 819.

47. DEC's decision to cancel the project is reasonable and prudent and in the public interest.

48. DEC's project development costs incurred for the Lee Nuclear Project, with the exception of costs relating to a Visitors' Center and the allowance for funds used during construction (AFUDC) for 2018, which were recommended for disallowance by the Public Staff and that the Company agreed to exclude,[5] are reasonable and prudent and should be amortized over a 12-year period, as requested by the Company.

49. It is not appropriate to permit the Company to earn a return on the unamortized balance of these project development costs during the amortization period, as requested. This rate treatment is consistent with Commission precedent and results in rates that are fair to both the Company and its ratepayers for the costs of the cancelled Lee Nuclear Project.

Nuclear Decommissioning Trust Fund (NDTF)

50. The Company proposes that the annual nuclear decommissioning expense be maintained at $0. The Public Staff has proposed that the Company's NDTF is overfunded and that the Company should be required to refund to customers $29 million per year. Because funds in the NDTF are to be used solely for decommissioning the Company's nuclear units, the Company is not permitted to withdraw funds from the NDTF for this purpose. Accordingly, the Public Staff proposes that the $29 million per year be refunded to customers through a "loan" from the Company's shareholders that would be repaid after decommissioning is complete.

[5] Excluding costs relating to the Visitors' Center and AFUDC for 2018, and extending the deferral period through April 2018, reduces the amount of the project development costs for Lee Nuclear from $353.2 million to $347.0 million. (See McManeus Rebuttal Ex. 3, p. 31, and Boswell Third Supplemental Ex. 1, p. 2 of 4.)

51. It is premature at this time to find that the NDTF is overfunded and that refunds should be required.

Depreciation

52. Use of a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs is reasonable in this case.

53. It is just and reasonable to use the escalation of terminal net salvage cost and the straight-line method of depreciation in determining escalation as performed in DEC's Decommissioning Study.

54. Use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346 is reasonable in this case.

55. The depreciation rates proposed by DEC in this case, with the exception of the adjustments discussed above, as filed by the Company as Doss Exhibits 3 and 4, are just and reasonable and should be approved.

Tax Changes

56. In this docket, the Commission has been presented with two proposals for the implementation of the Tax Act, one by the Company and one by the Public Staff. The Company proposal would:

(a) Implement an immediate reduction in its revenue requirements to reflect collection of federal corporate income tax at the 21% rate instead of the 35% rate.

(b) Implement flow back of federal excess deferred income taxes (Federal EDIT) to customers, as follows:

   (i) For Federal EDIT protected under Internal Revenue Service (IRS) normalization rules, in accordance with those rules;

   (ii) For Federal EDIT not protected by normalization rules, but related to property, plant and equipment (PP&E), over a 20-year period; and

   (iii) For Federal EDIT not protected by normalization rules, but not related to PP&E, through a five-year rider (federal unprotected non-PP&E rider).

(c) As a cash flow mitigation measure, increase the revenue requirement by $200 million, through any of a variety of mechanisms.

57. The Public Staff proposal would implement the Tax Act by implementing the same immediate reduction in revenue requirements based upon the tax rate reduction, implement the IRS-prescribed flow back of protected Federal EDIT, and implement the flowback of all unprotected Federal EDIT through a five-year rider. The Public Staff proposal would not provide any cash flow mitigation measures.

58. It is appropriate to reflect the 21% Federal corporate income tax rate specified in the Tax Act in DEC's revenue requirement in this proceeding. It is further appropriate to deny DEC's proposed $200 million cash flow mitigation measure and to require DEC to maintain all EDIT resulting from the Tax Act in a regulatory liability account pending flow back with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding, whichever is sooner.

Job Retention Rider (JRR)

59. The Company's proposed JRR is intended to allow the Company to prevent the loss of North Carolina jobs and the customer's related load.

60. Because gas pipelines are fixed investments that are not easily relocated, extending the benefits of a JRR to gas pipeline companies would not prevent the loss of North Carolina jobs. Companies involved in the "transportation or preservation of a raw material of a finished product" should not be eligible to participate in a JRR.

61. The Job Retention Tariff (JRT) Guidelines state that this tariff is intended to be temporary and to establish a maximum effective time of five years or a cap of five years. However, under the current economic circumstances, a shorter period of time, possibly one or two years, may achieve the intended result. Thus, a one-year pilot with the option of a renewal for a second year is an appropriate time frame for the current JRR.

62. The JRR proposed by the Company, as modified by the Stipulation and this Order, is not unduly discriminatory and is in the public interest.

63. Ratepayers, the Company, and its shareholders all benefit from the retention of North Carolina jobs and the load related to those jobs.

64. The Company's recovery of the JRR revenue credits should be reduced by $4.5 million each year the JRR is in effect, if more than one year, to recognize the benefit to shareholders of the JRR.

CCR Cost Deferral

65. In Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, DEP and DEC jointly filed a request that the Commission issue an order authorizing them to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements regarding CCRs. By Order dated July 10, 2017, the Commission consolidated DEC's request with the present general rate case. DEC

and the Public Staff supported the deferral in their testimony in this docket. The deferral request is reasonable and appropriate.

66. DEC expects to incur substantial costs related to CCRs in future years. It is just and reasonable to allow deferral of those costs, with a return at the net-of-tax overall cost of capital approved in this Order during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases.

67. It is reasonable and appropriate to add a return based on the net-of-tax overall cost of capital approved in DEC's last general rate case to the amount of deferred coal ash costs, as approved in this proceeding, for the period through the effective date of rates approved in this proceeding. The federal tax rate appropriate to use for the 2018 portion of the carrying costs is 21%.

68. It is reasonable and appropriate to use a mid-month cash flow convention for calculation of the return on the principal amount of deferred CCR expenditures. Compounding should take place at the beginning of January of each year.

Recovery of CCR Costs

69. Since its last rate case, DEC has become subject to new legal requirements relating to its management of coal ash. These new legal requirements mandate the closure of the coal ash basins at all of the Company's coal-fired power plants. Since its last rate case, DEC has incurred significant costs to comply with these new legal requirements.

70. On a North Carolina retail jurisdiction basis, the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, amount to $545.7 million. DEC is eligible to recover these coal ash basin closure costs. The actual coal ash basin costs incurred by DEC are known and measurable, reasonable and prudent, and, to the extent capital in nature, used and useful in the provision of service to the Company's customers. Further, DEC proposes that these costs be amortized over a five-year period, and that it earn a return on the unamortized balance. Under normal circumstances, the five-year amortization period proposed by the Company is appropriate and reasonable, and absent any management penalty, should be approved, and under normal circumstances the Commission within its discretion would allow the Company to earn a return on the unamortized balance.

71. Under the present facts, a management penalty in the approximate sum of $70 million is appropriate with respect to DEC's CCR remediation expenses accounted for in the earlier established Asset Retirement Obligation (ARO) with respect to costs incurred through the end of the test year, as adjusted. Through its use of available ratemaking mechanisms, the Commission is effectively implementing an estimated $70 million penalty by amortizing the $545.7 million over five years with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $14 million for each of the five years.

72. DEC further proposes that it recover on an ongoing basis $201 million in annual coal ash basin closure costs, subject to true-up in future rate cases. The amount sought by the Company is based upon its actual test year (2016) spend. The Company's proposal to recover these ongoing costs as a portion of the rates approved in this Order is not appropriate. Rather, it is appropriate to allow DEC to record its January 1, 2018, and future CCR costs in a deferral account until its next general rate case.

Provisional CCR Cost Recovery

73. DEC's recovery of the CCR costs approved in this proceeding should not be through provisional rates.

CCR Allocation Guidelines

74. It is reasonable and appropriate to allocate all system-level CCR costs using a comprehensive allocation factor that allocates the costs to the entire DEC system.

75. It is reasonable and appropriate to allocate all CCR expenditures by an energy allocation factor, rather than a demand-related production plant allocation factor.

Insurance Litigation

76. It is appropriate, even if this case is appealable to a higher court, to require that DEC, within ten days of the resolution by settlement, dismissal, judgment, or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEC.

77. It is appropriate to require DEC to place all insurance proceeds it receives or recovers in the Insurance Case in a regulatory liability account and to hold such proceeds until the Commission enters an order directing DEC regarding the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the net-of-tax overall rate of return authorized for DEC in this Order.

78. If meritorious concerns are raised by any party to this docket, or by the Commission, regarding the reasonableness of DEC's efforts to obtain an appropriate amount of recovery in the Insurance Case, it is appropriate to require DEC to bear the burden of proving that it exercised reasonable care and made reasonable efforts to obtain the maximum recovery in the Insurance Case.

Accounting for Deferred Costs

79. The Company is authorized to receive a specific amount of revenue for each of the several deferred costs approved by this Order. If DEC receives revenue for any

deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until its next general rate case.

Revenue Requirement

80. After giving effect to the approved Stipulation and the Commission's decision on contested issues, the annual revenue requirement for DEC will allow the Company a reasonable opportunity to earn the rate of return on its rate base that the Commission has found just and reasonable.

81. DEC should recalculate and file the annual revenue requirement with the Commission within ten days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DEC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

82. The appropriate revenue requirement for the first four years should be reduced by the State EDIT Rider decrement of $60.102 million.

Just and Reasonable Rates

83. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DEC, DEC, and all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-6

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On August 25, 2017, DEC filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $611 million, or 12.8%, in its annual electric sales revenues from its North Carolina retail electric operations. DEC is also proposing the Grid Rider to recover ongoing costs related to the modernization of the Company's electric grid, referred to as the Power Forward initiative. The Grid Rider brings the total impact of the Company's rate request in its Application to approximately

$647 million, a 13.6% increase across all customer classes. DEC submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2016, updated for certain known and actual changes. After rebuttal and supplemental filings, the amount of the Company's requested revenue requirement increased to $700 million. The Company also requested a Grid Rider to recover $35.2 million in its first year.

Company witness Fountain testified that major generating plant projects, nuclear development work, grid improvements and modernization, additions and plant-related expenses, improvements to the Company's Customer Information System (CIS), and additional funding for vegetation management account for the majority of the total additional requested annual revenue requirement. Tr. Vol. 6, p. 163. The remainder of the requested rate adjustment is to recover costs related to environmental requirements associated with the mandated closure of ash basins and other ongoing operational costs, offset by certain regulatory liabilities and decreases in rate base. Id. In addition, DEC proposes a Grid Rider to recover ongoing costs related to the modernization of the Company's electric grid, referred to as the Power Forward Carolinas initiative (Power Forward). Id. at 162.

Witness Fountain detailed the Company's recent investments driving the Company's requested rate increase. Id. at 166-77. He described numerous nuclear, fossil, hydro, and solar projects that DEC has completed since its last rate case. Id. at 166. He explained that the Company has retired half of its older, less-efficient coal-fired generation units and is providing customers with increasingly clean energy from new gas-fueled generation, carbon-free nuclear plants, and utility scale solar projects. Id. at 165. For example, he described the Company's new Lee CC plant, which features state-of-the-art technology for increased efficiency and significantly reduced emissions. Id. at 167. In addition, the Company has added two solar facilities to DEC's generating mix and recently completed its relicensing effort for the Catawba-Wateree hydro project. Id.

Since the last rate case, the Company has also made investments designed to improve reliability and customer service. Id. at 168-69. Witness Fountain provided an overview of the Company's ongoing deployment of AMI, which will work in tandem with the Company's implementation of a new Customer Information System (CIS), called "Customer Connect," as well as the grid investments that make up Power Forward. Id. at 168-72. In addition, the Company has requested an increase in the pro forma for vegetation management to help improve grid reliability. Id. at 172-73.

Witness Fountain also outlined the coal ash basin closure costs the Company is seeking to recover in this case and emphasized that the Company is not seeking recovery of any costs incurred in response to the release of coal ash from the Dan River Steam Station in February 2014. Id. at 169-70, 173-77. The Company's Application also requests that the Commission permit DEC to cancel the Lee Nuclear Project as originally envisioned[6] and to recover costs for project development work completed for the project. Id. at 167-68. Finally, witness Fountain noted that the cost increases requested in this case are partially offset by the return of a deferred tax liability to customers. Id. at 170.

Witness Fountain explained that DEC's proposed rate adjustment means customers will still be paying lower rates today than they were in 1991 on an inflation-adjusted basis, and customers will continue to pay rates below the national average and competitive with other utilities in the region. Id. at 178. In addition, he pointed out that the typical residential customer's bill has declined from those approved in 2013 due, in part, to the Company prudently managing fuel costs and jointly dispatching the generation fleet to save $296 million. Id. at 177-78.

Witness Fountain also described the Company's ongoing efforts to mitigate customers' rate impacts. Id. at 180-85. He stated that to help customers reduce bills, the Company is continuing to expand and enhance its portfolio of DSM and EE programs. Id. at 182. According to witness Fountain, the Company offers customers more than a dozen energy-saving programs for every type of energy user and budget; EE programs currently save its customers in the Carolinas over 4.3 billion kWh annually, or over $357 million, which is about 5.4% of total retail kWh sales. Id. Combined, DEC's demand-side management (DSM) and Energy efficiency (EE) programs offset capacity requirements by the equivalent of over seven power plants. Id. Witness Fountain also described how the Company's Share the Warmth program helps low-income individuals and families cover home energy bills. Id. at 183. Since its inception, the program has provided approximately $26 million in assistance to DEC customers in North Carolina. Id. He explained that the Company allows customers a bill management option that allows them to spread out the impacts of seasonal fluctuations into 12 equal monthly payments. Id. at 184. The Company also offers payment arrangements to eligible customers who are having difficulty paying their entire bill by the due date. Id.

Witness Fountain indicated that the Company's most important objective is to continue providing safe, reliable, affordable, and increasingly clean electricity to its customers with high quality customer service, both today and in the future. Id. at 63. He concluded that the request for a rate increase is made to support investments that benefit DEC customers, and the Company strives to ensure that those investments are made in a cost-effective manner that retains the Company's level of service and competitive rates. Id. at 64.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-10

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the testimony of DEC witnesses Fountain, McManeus, Hevert, De May, and Pirro, the testimony of Public Staff witnesses Boswell, Maness, and Parcell, the Stipulation, and the Lighting Settlement.

[6] As discussed below, the Company seeks to retain the combined operating license (COL) granted by the Nuclear Regulatory Commission (NRC) in case circumstances change. Id. at 167.

On February 28, 2018, DEC and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement, which resolves some of the issues in this proceeding between these two parties and provides for a revenue requirement increase of approximately $537,500,000 based on the settled issues. The Stipulation is based upon the same test period as the Company's Application.

Witness Fountain explained that the Stipulation would resolve many, but not all, of the revenue requirement issues between the Company and the Public Staff.[7] Tr. Vol. 6, p. 218. He outlined the key aspects of the Stipulation as follows:

Cost of Capital – The Stipulating Parties have agreed to a rate of return on equity of 9.9%, based upon a capital structure containing 52% equity and 48% debt as described by Company witnesses Hevert and De May. Id. The Company's debt cost rate shall be set at 4.59%. Id. at 218-19. The resulting weighted average rate of return is 7.35%. Id. at 219.

Distribution Vegetation Management – The Public Staff and DEC have agreed on the amount of distribution vegetation management expenses in an annual amount of $62.6 million on a total system basis. Id. This amount reflects rising contractor rates that are affecting the Company's costs in effectuating its trim cycles. Id. The Stipulation also includes commitments for certain catch up miles and a plan for transparent reporting so that the Commission and interested parties can be informed of the Company's vegetation management plans and expenditures. Id.

Lee CC – The Public Staff and the Company have agreed upon the appropriate level of ongoing O&M and deferred expenses for Lee CC. Id. The Stipulating Parties noted in the Stipulation that Lee CC is not anticipated to come online until March, and the Stipulation contains a plan to hold the record open solely for the purpose of verifying the amounts to be included in rates and confirmation that the plant is operational. Id.

Customer Connect Expenses – The Public Staff and the Company have resolved issues related to this important initiative such that the Company, if the Stipulation is approved, would be allowed to accrue and recover AFUDC on costs during the implementation period to be captured in a regulatory asset. Id. at 219-20.

[7] Witness Fountain identified the Unresolved Issues as follows: (1) the Company's request to recover its deferred coal ash costs and its ongoing environmental compliance costs necessary to safely close the Company's coal ash basins, as well as the method by which the Company should allocate coal ash costs; (2) whether it is appropriate to allow a return on the unamortized balance of costs relating to the Lee Nuclear Project during the amortization period; (3) the status of the Company's Nuclear Decommissioning Trust Fund and the Public Staff's proposal to adjust nuclear decommissioning expense; (4) the final update month to be used for ratemaking in this case; (5) the methodology for calculating customer usage through December 2017; (6) the manner in which the Federal Tax Cuts and Jobs Act should be addressed in this case; (7) the amount of annual depreciation expense and associated accumulated depreciation to be used for ratemaking in this case; (8) whether a Grid Rider should be adopted in this proceeding, and if so, which costs would be included in the Grid Rider and the structure of the Grid Rider; (9) the amount of the Basic Facilities Charge; and (10) any other revenue requirement or non-revenue requirement issues other than those issues specifically addressed in the Stipulation or agreed upon in the testimony of the Stipulating Parties. Tr. Vol. 6, pp. 223-24. As addressed by witness Pirro, the Company also has a different view than the Public Staff on certain items related to the Job Retention Rider. Id. at 224.

Other Adjustments – Revenue requirement adjustments were also agreed upon in the Stipulation for Aviation Expenses, Executive Compensation, Board of Directors, Lobbying, Sponsorships, and Donations for the U.S. Chamber of Commerce, Incentive Compensation, and Outside Services, as well as Duke Energy-Piedmont Natural Gas (Piedmont) merger costs to achieve, salaries and wages, and DEBS allocations. Id. at 220. The Stipulating Parties have also agreed to the implementation of a Coal Inventory Rider, and the Company has committed to study coal inventory levels and provide those results for review. Id. The Stipulating Parties also agreed on the return of the state excess deferred income taxes to customers through a four-year rider. Id.

Job Retention Rider – The Stipulating Parties have also agreed to resolve the Company's Job Retention Rider proposal, except for two remaining items to be decided upon by the Commission, as described in the Stipulation. Id.

Other Cost of Service and Rate Design Matters – The Stipulating Parties have also agreed upon rate design and cost of service study parameters as proposed by Company witnesses Pirro and Hager and Public Staff witness Floyd (aside from the amount of the Basic Facilities Charge, which is not resolved by the Stipulation). Id.

Recovery of CCR Costs Through the Fuel Adjustment Clause – The Company has agreed to withdraw its request to recover certain CCR costs through the fuel adjustment clause related to the excavation and movement of CCRs from the Company's Riverbend Plant to the Brickhaven Facility. Id. at 221. The effect of this provision of the Stipulation is that the Company and the Public Staff agree that these costs are left in DEC's deferred CCR balance for consideration of recovery in the Company's base rates. Id.

These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Stipulation are shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, which provide sufficient support for the annual revenue required on the issues agreed to in the Stipulation. The Stipulating Parties' recommended revenue requirement increase after settled issues is approximately $541,117,000. However, the total adjustment in base rate revenues and the resulting average adjustment cannot be determined until the Commission resolves the Unresolved Issues.[8]

Witness Fountain testified that he attended public witness hearings held by the Commission in this matter and followed the consumer statement positions filed in this docket. Tr. Vol. 6, p. 221. He listened to customers' concerns about the impacts of any

[8] Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues shows DEC's revised requested increase incorporating the provisions of the Stipulation and the Company's position on the Unresolved Issues. The resulting proposed revenue requirement increase of the Company is $472,249,000. Boswell Third Supplemental and Stipulation Exhibit 1 Corrected shows the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Stipulation and a number of downward adjustments reflecting the Public Staff's position on the Unresolved Issues. The resulting proposed revenue requirement by the Public Staff is a decrease in the base rate revenue requirement of $101,230,000.

rate increase on their families and businesses and noted that the Company is very mindful of these concerns. Id. Witness Fountain believes that the concessions the Company made in the Stipulation fairly balance the needs of DEC's customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to its customers. Id. at 222. He added that the Company's rates need to be adjusted to reflect these investments. Id. Witness Fountain stated that given the size of the necessary capital and compliance expenditures the Company is facing, it is essential that DEC maintain its financial strength and credit quality, so that it will be in a position to finance these needs on reasonable terms for the benefit of its customers. Id. In his opinion, the Company has been able to strike that balance with the Stipulation. Id.

DEC witnesses McManeus, Hevert, De May, and Pirro also testified in support of the Stipulation. Witness De May testified that the Stipulation will support the Company's ability to achieve its financial objectives. Tr. Vol. 4, p. 89. Witness Hevert stated that although the stipulated rate of return on equity is somewhat below the lower bound of his recommended range, he understands the Company has determined that the terms of the Stipulation, in particular the stipulated return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable. Tr. Vol. 4 pp. 407-08. Witness Pirro testified concerning the effects of the partial settlement on DEC's proposed JRR and the Company's proposed reallocation of revenue resulting from the agreement among the Company, NCLM, and the Cities of Concord and Kings Mountain regarding lighting issues. Tr. Vol. 19, pp. 105-09. Witness McManeus presented exhibits showing the monetary effect of the various issues addressed in the Stipulation.

Public Staff witnesses Boswell, Maness, and Parcell also supported the Stipulation. Witness Boswell stated that the most important benefits of the Stipulation are an aggregate reduction in the increase of specific expense items requested in the Company's application and the avoidance of protracted litigation by the Stipulating Parties before the Commission and, possibly, the appellate courts. Tr. Vol. 26, p. 628. Witness Boswell also presented schedules showing the financial impact of the Stipulation. Witness Maness testified on the impact of the Stipulation on the unresolved CCR issues, and witness Parcell stated that the Stipulation reflects the result of good faith "give-and-take" and compromise-related negotiations among the parties. Tr. Vol. 26, p. 890.

As the Stipulation and the Lighting Settlement have not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I the Supreme Court held that:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The

> Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703. However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of Chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16.

The Commission gives substantial weight to the testimony of the Company and Public Staff witnesses regarding the Stipulation and the Lighting Settlement, and finds and concludes that the Stipulation and the Lighting Settlement are the product of the "give-and-take" of the settlement negotiations between DEC and the Public Staff, as well as between DEC and NCLM, and the Cities of Concord, Kings Mountain, and Durham, in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

Ample evidence exists in the record to support all of the provisions of the Stipulation, including those which have been contested by some intervenors other than the Stipulating Parties. Accordingly, the Commission is fully justified in adopting the Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the Stipulation "is just and reasonable to all parties in light of all the evidence presented." CUCA I, 348 N.C. at 466, 500 S.E.2d at 703. The Commission hereby adopts the Lighting Settlement in its entirety, and its conclusions as to the individual provisions are discussed in the rate design section of this order. The Commission hereby adopts the Stipulation in its entirety, and its conclusions as to the individual provisions of the Stipulation are set forth more fully below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-19

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the public witnesses, the testimony and exhibits of Company witnesses Hevert and De May, Public Staff witness Parcell, Commercial Group witnesses Chriss and Rosa, AGO witness Woolridge, CIGFUR III witness Phillips, Tech Customers witness Strunk and CUCA witness O'Donnell, and the entire record of this proceeding.

Rate of Return on Equity

In its Application, the Company requested approval for its rates to be set using a rate of return on equity of 10.75%. The Stipulation provides for a rate of return on equity of 9.9%, which is a decrease from the 10.2% level authorized by the Commission in the Company's last rate case. For the reasons set forth herein, the Commission finds that a rate of return on equity of 9.9% is just and reasonable.

Rate of return on equity, also referred to as the cost of equity capital, is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which a Stipulation between the utility and the consumer advocate has been reached. In the absence of a settlement agreed to by all parties, the Commission must still exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including the rate of return on equity. See, e.g., CUCA I, 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541, 546-47 (2013) (Cooper I). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness Hevert, Public Staff witness Parcell, Commercial Group witnesses Chriss and Rosa, AGO witness Woolridge, CIGFUR III witness Phillips, Tech Customers witness Strunk, and CUCA witness O'Donnell. No rate of return on equity expert evidence was presented by any other party.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. Cooper I, 366 N.C. 484, 739 S.E.2d at 548. This was a factor newly announced by the Supreme Court in its Cooper I decision, and which was not previously required by the Commission, the Court of Appeals, or the Supreme Court as an element to be considered in connection with the Commission's determination of an appropriate rate of return on equity. The Commission's discussion of the evidence with respect to the findings required by Cooper I is set out in detail in this Order.

Cooper I was the result of the Supreme Court's reversal and remand of the Commission's approval of the agreement regarding the rate of return on equity in a stipulation between the Public Staff and DEC in DEC's 2011 Rate Case. The Commission has had occasion to apply both prongs of Cooper I in subsequent orders, specifically the following:

- Order Granting General Rate Increase in DEP's 2013 Rate Case, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the

Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III);[9]

- Order on Remand resulting from the Supreme Court's Cooper I decision, in Docket No. E-7, Sub 989 (October 23, 2013) (DEC Remand Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014) (Cooper IV);
- Order Granting General Rate Increase in DEC's 2013 Rate Case, Docket No. E-7, Sub 1026 (September 24, 2013) (2013 DEC Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 767 S.E.2d 305 (2015) (Cooper V);
- Order on Remand resulting from the Supreme Court's Cooper II decision, in Docket No. E-22, Sub 479 (July 23, 2015) (DNCP Remand Order), which was not appealed to the Supreme Court;
- Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, in Docket No. E-22, Sub 532, dated December 22, 2016 (2016 DNCP Rate Order), which was not appealed to the Supreme Court; and
- Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, in Docket No. E-2, Sub 1142, dated February 23, 2018 (2018 DEP Rate Order).

In order to give full context to the Commission's decision herein and to elucidate its view of the requirements of the General Statutes as they relate to rate of return on equity, as interpreted by the Supreme Court in Cooper I, the Commission deems it important to provide in this Order an overview of the general principles governing this subject.

A. Governing Principles in Setting the Rate of Return on Equity

First, there are, as the Commission noted in the 2013 DEP Rate Order, constitutional constraints upon the Commission's rate of return on equity decisions established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C.

[9] An intervening Cooper case, State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014) (Cooper II), arose from the 2012 Rate Case by Dominion North Carolina Power (DNCP) and resulted in a remand to the Commission, inasmuch as the Commission's Order in that case predated Cooper I.

> 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

2013 DEP Rate Order, at 29.

Second, the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in Missouri ex rel. Southwestern Bell Tel. Co. v. Missouri Pub. Serv. Comm'n, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds…and it is also true of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306. (Brandeis, J. dissenting) (emphasis added). Similarly, the United States Supreme Court observed in Hope, "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business…[which] include service on the debt and dividends on the stock." Hope, 320 U.S. at 591, 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that "the term 'cost of capital' may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., The Regulation of Public Utilities (Public Utilities Reports, Inc. 1993), at 388. Professor Roger Morin approaches the matter from the economist's viewpoint:

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.

*   *   *

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., Utilities' Cost of Capital (Public Utilities Reports, Inc. 1984), at 19-21 (emphasis added). Professor Morin adds: "The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Id. at 20 (emphasis added).

Changing economic circumstances as they impact DEC's customers may affect those customers' ability to afford rate increases. For this reason, customer impact weighs heavily in the overall rate setting process, including, as set out in detail elsewhere in this Order, the Commission's own decision of an appropriate authorized rate of return on equity. In addition, in the event of a settlement, customer impact no doubt influences the process by which the parties to a rate case decide to settle contested matters and the level of rates achieved by any such settlement.

However, a customer's ability to afford a rate increase has absolutely no impact upon the supply of or the demand for capital. The economic forces at work in the competitive capital market determine the cost of capital – and, therefore, the utility's required rate of return on equity. The cost of capital does not go down because some customers may find it more difficult to pay for an increase in electricity prices as a result of prevailing adverse economic conditions, any more than the cost of capital goes up because some customers may be prospering in better times.

Third, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (Public Staff). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." 2013 DEP Rate Order, at 37. The Commission noted in that Order:

> The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than at other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

Id. Indeed, in Cooper I the Supreme Court emphasized "changing economic conditions" and their impact upon customers. Cooper I, 366 N.C. at 484, 739 S.E.2d at 548.

Fourth, while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." 2013 DEP Rate Order, at 38.

Fifth, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on equity. Public Staff, 323 NC 481, 490, 374 S.E.2d 361, 369. As the Commission also noted in the 2013 DEP Rate Order:

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process, the appropriate ROE [rate of return on equity] the one requiring the greatest degree of subjective judgment by the Commission. Setting an ROE [rate of return on equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
>
>> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>>
>> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have

> been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.
>
> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382. (notes omitted).

2013 DEP Rate Order, pp. 35-36.

Thus, the Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors – the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service.

The Supreme Court in Cooper V affirmed the 2013 DEC Rate Order, in which this framework was fully articulated. But to the framework the Commission can add additional factors based upon the Supreme Court's decisions in Cooper III, Cooper IV, and Cooper V. Specifically, the Supreme Court held that nothing in Cooper I requires the Commission to "quantify" the influence of changing economic conditions upon customers (see, e.g., Cooper V, 367 N.C. at 745-46, 767 S.E.2d at 308; Cooper IV, 367 N.C. at 650, 766 S.E.2d at 829; Cooper III, 367 N.C. at 450, 761 S.E.2d at 644), and, indeed, the Supreme Court reiterated that setting the rate of return on equity is a function of the Commission's subjective judgment: "Given th[e] subjectivity ordinarily inherent in the determination of a proper rate of return on common equity, there are inevitably pertinent factors which are properly taken into account but which cannot be quantified with the kind of specificity here demanded by [the appellant]." Cooper III, 367 N.C. at 450, 761 S.E.2d at 644, quoting Public Staff, 323 N.C. at 498; 374 S.E.2d at 370.

Finally, the Supreme Court discussed with approval the Commission's reference to and reliance upon expert witness testimony that used econometric models that the Commission had noted "inherently" contained the effects of changing economic circumstances upon customers, and also discussed with approval the Commission's reference to and reliance upon expert witness testimony correlating the North Carolina economy with the national economy. See, e.g., Cooper V, 367 N.C. at 747, 767 S.E.2d at 308; Cooper III, 367 N.C. at 451, 761 S.E.2d at 644.

It is against this backdrop of overarching principles that the Commission turns to the evidence presented in this case.

B. Application of the Governing Principles to the Rate of Return Decision

1. Evidence from Expert Witnesses on Cost of Equity Capital

Company witness Hevert recommended in his direct testimony a rate of return on equity of 10.75%, which was slightly above the midpoint of his recommended range of 10.25% to 11.00%. Witness Hevert's direct testimony explained the importance of a utility being allowed to earn a rate of return on equity that is adequate to attract capital at reasonable terms, under varying market conditions, and that will enable the utility to provide safe, reliable electric service while maintaining its financial integrity. Witness Hevert explained that unlike the cost of debt, the cost of equity is not observable and must be estimated based on market data. Witness Hevert noted that since all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return recommendations. Witness Hevert used the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model; the Capital Asset Pricing Model (CAPM); and the Bond Yield Risk Premium. He testified that his recommendation also takes into consideration factors such as DEC's generation portfolio and the risks associated with environmental regulations, flotation costs, and DEC's planned capital investment program. Witness Hevert also provided extensive testimony concerning the capital market environment and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness Hevert also focused upon capital market conditions as they affect the Company's customers in North Carolina.

To calculate the dividend yield for the DCF, witness Hevert used the average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days as of June 16, 2017. He then calculated the DCF results using each of the following growth terms:

- The Zack's consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates; and
- The Value Line earnings growth estimates.

Witness Hevert testified that for each proxy company he calculated the mean, mean high, and mean low results. For the mean result, he combined the average of the

EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. His constant growth DCF results ranged from 7.91% to 9.83%.[10]

He testified with regard to his constant growth DCF that regardless of the method employed, an authorized rate of return on equity that is well below returns authorized for other utilities (1) runs counter to the Hope and Bluefield "comparable risk" standard, (2) would place DEC at a competitive disadvantage, and (3) makes it difficult for DEC to compete for capital at reasonable terms.

DEC witness Hevert testified that the Multi-Stage DCF model, which is an extension of the constant growth form, enables the analyst to specify growth rates over three distinct stages (i.e., time periods). As with the constant growth form of the DCF model, the Multi-Stage form defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. He testified in the first two stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period (i.e., the terminal price). He calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (i.e., the discount rate) and the long-term expected growth rate.

Witness Hevert testified that his Multi-Stage DCF long-term growth rate was 5.38% based on the real gross domestic product (GDP) growth rate of 3.22% from 1929 through 2016 and an inflation rate of 2.09%. He testified that the GDP growth rate is calculated as the compound growth rate in companies. Witness Hevert testified that his Multi-Stage DCF analysis produced a range of results from 8.70% to 9.31%. Using the proxy group price-to-earnings ratio to calculate a terminal valve, his Multi-Stage DCF produced a range of results from 9.52% to 11.05%.

Witness Hevert testified that for his CAPM analysis risk-free rate, he used the current 30-day average yield on 30-year Treasury bonds of 2.90% and the near-term projected 30-year Treasury yield of 3.40%. For the market risk premium, he calculated the market capitalization weighted average total return based on the constant growth DCF model for each of the Standard & Poor's (S&P) 500 companies using data from Bloomberg and Value Line. He then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived forward looking market risk premium estimate. Witness Hevert used the beta coefficients reported by Bloomberg and Value Line. He testified that his CAPM analysis suggested a rate of return on equity range of 9.11% to 11.05%.

[10] Table 11 in the rebuttal testimony of witness Hevert contains updated analytical results for his DCF, CAPM, and Bond Yield Risk Premium analyses. However, in summarizing his rebuttal testimony, witness Hevert testified that "[n]one of their [opposing witnesses] arguments caused me to revise my conclusions or recommendations."

Witness Hevert testified that for his risk premium analysis, he estimated the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. He testified that the equity risk premium is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the cost of equity, and others that consider historical, or ex-post, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the equity risk premium.

Witness Hevert testified that he first defined the risk premium as the difference between the authorized rate of return on equity and the then-prevailing level of the long-term 30-year Treasury yield. He then gathered data for 1,517 electric utility rate proceedings between January 1980 and June 16, 2017. In addition to the authorized rate of return on equity, he also calculated the average period between the filing of the case and the date of the final order (the "lag period"). In order to reflect the prevailing level of interest rates during the pendency of the proceedings, he calculated the average 30-year Treasury yield over the average lag period of approximately 201 days. He testified that to analyze the relationship between interest rates and the equity risk premium, he used regression analyses. Witness Hevert testified that based upon the regression coefficients, the implied rate of return on equity in his risk premium analysis is between 9.97% and 10.33%.

Public Staff witness Parcell performed three rate of return on equity analyses using the constant growth DCF, the CAPM, and comparable earnings.

Witness Parcell considered five indicators of growth in his DCF analyses:

- Years 2012-2016 (five-year average) earnings retention, or fundamental growth (per Value Line);
- Five-year average of historic growth in EPS, dividends per share (DPS), and book value per share (BVPS) (per Value Line);
- Years 2017, 2018, and 2020-2022 projections of earnings retention growth (per Value Line);
- Years 2014-2016 to 2020-2022 projections of EPS, DPS, and BVPS (per Value Line); and
- Five-year projections of EPS growth (per First Call).

Witness Parcell testified that investors do not always use one single indicator of growth. His analysis using these five dividend growth indicators materially differed from DEC witness Hevert's sole use of analysts' predictions of EPS growth to determine DCF dividend growth.

Witness Parcell performed his DCF analysis on his proxy group of 11 companies, where using only the high mean growth rate the cost of capital was 8.2%, and the Hevert proxy group of 20 companies, where using only the highest mean growth rate the cost of capital was 9.2%. He recommended a DCF rate of return on equity of 8.7% for DEC as the mid-point of the two highest mean growth rates.

Witness Parcell testified that the constant growth DCF model currently produced cost of equity results that are lower than has been the case in recent years. This is, in part, a reflection of the decline in capital costs (e.g., in terms of interest rates). He believed that the constant growth DCF model remains relevant and informative. It was also his personal experience that of all available cost equity models, this model is used the most by cost of capital witnesses. Nevertheless, in order to be conservative, he focused only on the highest of the DCF results in making his recommendations.

Witness Parcell testified that he did not perform a multi-stage DCF, as he did not believe that the results of a properly-constructed multi-stage DCF would materially differ from the results of his constant-growth DCF.

Public Staff witness Parcell also performed a CAPM analysis, which describes the relationship between a security's investment risk and its market rate of return. For his risk-free rate, he used the three-month average yield for 20-year Treasury bonds. For the beta, which indicates the security's variability of return relative to the return variability of the overall capital market, he used the most recent Value Line beta for each company in his proxy group. He calculated the risk premium by comparing the annual returns on equity of the S&P 500 with the actual yields of the 20-year Treasury bonds, by comparing the total returns (i.e., dividends/interest plus gains/losses) for the S&P 500 group as well as long-term government bonds, using both the arithmetic and geometric means. These analyses revealed the average expected risk premium to be 5.8%. His CAPM results collectively indicated a rate of return on equity of 6.3% to 6.7% for the Parcell and Hevert proxy groups.

However, witness Parcell did not directly consider his CAPM results. He testified that he has conducted CAPM studies in his cost of equity analyses for many years. He stated that it is apparent that the CAPM results are currently significantly less than the DCF and comparable earnings results. According to his testimony, there are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity returns that have been experienced beginning with the Great Recession and continuing over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectation of returns in a negative fashion.

Witness Parcell testified that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case, as interest rates have remained low and have continued to decline for the past six-plus years. As a result, he believes that it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not reflect investor expectations.