potentially stabilize profits rather than reduce them.[2] Decoupling revenues from sales volumes was first implemented in California and New York in the 1980s. Decoupling did not gain momentum outside of California and New York for decades and only recently implemented in various other state regulatory jurisdictions across the US for electric, natural gas, and water public utilities. Fig. 1 is a map depicting the extent of decoupling across the US developed by the National Resources Defense Council[3] . While Fig. 1 shows the extent of decoupling across the US for electricity and natural gas utility industries, it does not show the same for water / wastewater utility industries. Fig. 1 shows that as of August 2018, 26 states have adopted gas decoupling (compared with 20 in 2013) and 17 have adopted electricity decoupling (compared with 14 in 2013).

The types of decoupling generally fall into three categories: fixed and variable rate mechanisms; lost revenue recovery from commodity sales reductions due specifically to energy or water efficiency programs; and fixed revenue true-up mechanisms. Fixed and variable rate mechanisms have a high fixed rate component that may or may not include a set maximum commodity volume included in the fixed rate with the variable rate being the rate for partial or all volume use. The fixed rate is intended to cover all or most fixed costs. Fixed rates are rarely used in the electric or gas utility industries but are frequently used for water utilities. Lost revenue recovery mechanisms allow the utility to collect the revenue lost directly from specific sales reductions due to energy or water efficiency programs. True-up mechanisms set a fixed overall level of revenues with the utility allowed to recover a shortfall in revenues from the fixed level in higher rates. Nadel and Herndon[4] discuss the future of the energy utilities industries and the role that decoupling as a form of alternative ratemaking may play in that future. Also, see Carter[5], Cavanaugh[6], Eto, Stoft, and Belden[7] and the American Council for an Energy Efficient Economy and Natural Resource Defense Council websites for discussion on the trends, theory and implementation of decoupling and various decoupling mechanisms.

One key consideration in many US regulatory rate proceedings and policy discussions is the impact of decoupling on the investment risk of a public utility and, subsequently, its cost of common equity (and therefore the allowed rate of return set by regulators). Since decoupling disassociates revenues from sales volumes, the intended impact is that it generates an increasingly stable and non-declining level of revenues and net income if sales do decline. Therefore, the public utility is expected to be perceived by investors as having lower investment risk, which would lead to a lower cost of common equity capital, that is, the investor required return.

Decoupling can also be viewed as exacerbating investment risk rather than decreasing it. To the extent that investors are concerned about a changing regulatory regime, uncertainty about the measurement of the savings impacts of conservation programs may exacerbate investors' perceived risk and the cost of common equity.

Decoupling is implemented with the intention of reducing or eliminating volume risk and therefore potentially affects the cost of common equity as stated above. If the utility hedges volume risk due to weather, which is the most likely cause of demand shocks to electric, gas or water commodities, hedging derivatives[8] allow the utility to insure such risk. If the utility hedges most of the commodity demand risk while meeting demand regardless of compensation mechanisms, the risk may fall or may not fall depending on the degree of diversification in the investor portfolio. For example, weather risk may or may not affect all common stocks in an investor's portfolio. Should a utility incur costs to hedge risks that do not materialize into an adverse effect, the hedges may not payoff. Therefore, volume risk is not always alleviated with decoupling. Essentially, the question is that although the risk of the business is not changed by reward mechanisms, as demand shocks (positive or negative) still occur, do investors perceive, as do some regulators and utility management, that decoupling reduces risk? While a change in the reward structure does not change the fundamental riskiness of a firm, it is the investors' perceived risk that affects the cost of common equity. While this is not likely to occur in an efficient market, it is not so obvious that financial markets are efficient. The existence of an efficient market is one of a number of assumptions that has been relaxed in the derivation of the recently developed financial model used in this paper. It is commonly known as the predictive risk premium model and technically known as the generalized consumption asset pricing model (GCAPM).[9]

The topic of this paper has been the subject of only a few empirical investigations so far by Wharton and Vilbert[10] and Vilbert, Wharton, Zhang and Hall[11] {collectively referred to as Wharton, et al. (2015, 2016)}. Moody's[12] has estimated the change in business risk and credit metrics due to decoupling, but not the impacts on the cost of capital.

[2] In response to the challenges to achieving the allowed return on common equity due to expected significant capital expenditures to repair and replace utility infrastructure, as well as declining per capita commodity consumption, the National Association of Regulatory Utility Commissioners (NARUC) recommends that regulators carefully consider and implement appropriate ratemaking measures so that water and sewer utilities have a reasonable opportunity to earn their allowed rate of return on common equity. Decoupling, or revenue adjustment stabilization mechanisms (RAM) separate rates / revenues from electricity, gas or water volumes sold. Such mechanisms address the effects of the more efficient use of the commodity and declining per capita consumption, for water, and to a lesser extent, electricity, while maintaining the financial soundness and viability of the utilities. With RAMs, utilities are made whole for revenue shortfalls from allowed revenues used to design rates, which generally result from weather and conservation efforts by customers. RAMs allow for the recovery / crediting of differences between actual and allowed quantity charge revenues. RAMs seem to be effective in mitigating the effects of regulatory lag and improving utilities' opportunities to earn their allowed returns on common equity while upgrading infrastructure, ensuring safe and reliable service, removing the incentive to sell more commodity, and helping to protect valuable natural resources. However, in base rate cases for utilities that have such mechanisms, the question often arises as to whether and to what extent the presence of such mechanisms reduces the utility's investment risk as well and to what extent such a perceived or actual reduction in risk should be reflected in the allowed return on common equity.

[3] National Resources Defense Council. (2018). www.nrdc.org/resources/gas-and-electric-decoupling.

[4] Nadel, S., and G. Herndon. (2014). The future of the utility Industry and the role of energy efficiency. American Council for an Energy Efficient Economy, Report Number U1404.

[5] Carter, S. (2001). Breaking the consumption habit: Ratemaking for efficient resource decisions. Electricity Journal, 14, 66-74.

[6] Cavanaugh, R. (2013). Report: "Decoupling" is transforming the utility industry. Natural Resources Defense Council.

[7] Eto, J., S. Stoft, and T. Belden. (1997). The theory and practice of decoupling utility revenues from sales. Utility Policy, 6, 43-55.

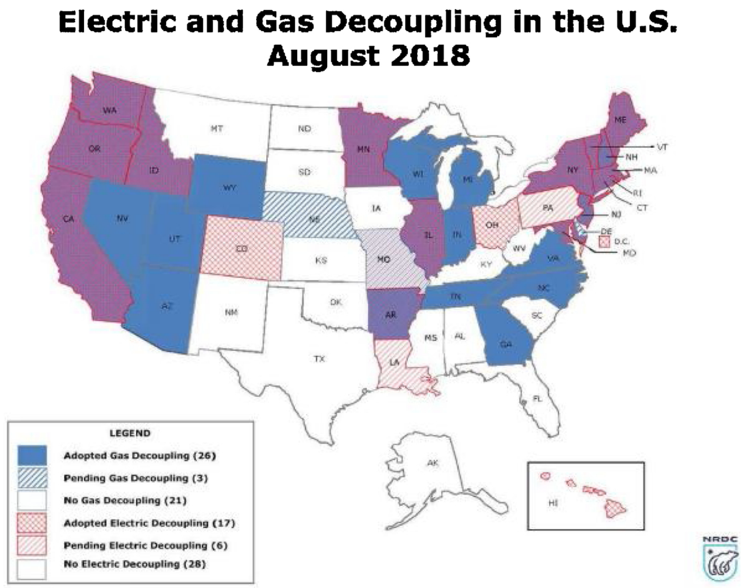
[8] Water derivatives, although not traded in markets as are gas and electricity futures and forwards, are created through private contracts. Some water distribution systems are interconnected to others and have various contracting structures for buying water if a demand shock should cause the need for more water that the incumbent system cannot supply. Some sewer systems have similar contracts to transfer excessive wastewater flows to another utility's treatment plant if their own capacity reaches its limit.

[9] A less technical discussion of this model can be found in "Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity Capital," by Richard A. Michelfelder, Pauline Ahern, Dylan D'Ascendis and Frank Hanley, *The Electricity Journal*, 26, 2013.

[10] Wharton, J. and M. Vilbert. (2015). Decoupling and the cost of capital. The Electricity Journal, 28, 19-28.

[11] Vilbert, M., J. Wharton, S. Zhang, and J. Hall. (2016). Effect on the cost of capital of ratemaking that relaxes the linkage between revenue and kwh sales, an updated empirical investigation of the electric industry. A Brattle Group Report.

[12] Moody's Investors Service. (2011). Decoupling and 21st Century Ratemaking. Special Comment.



	2013		2018	
	Utilities	States	Utilities	States
Gas	49	20	64	26
Electric	24	14	41	17
Total	73	25	105	32

Fig. 1. Electric and Gas Decoupling in the U.S. August 2018.
Source: https://www.nrdc.org/resources/gas-and-electric-decoupling, accessed March 31, 2019.

There are no empirical studies on water utilities such as those performed in this study.

Wharton, et al. (2015, 2016) concluded that decoupling has no statistically significant measurable impact on the public utility cost of common equity. They found that while decoupling may reduce revenue volatility, it may not reduce investment risk. In fact, they find that it may actually exacerbate risk as decoupling regulatory policy is viewed as a new and uncertain regime and may be used to promote other regulatory policy goals and create regulatory risk.[13] Reductions in peak loads and the commodity sales impacts of consumer energy or water efficiency measures are difficult and expensive to estimate. This difficulty introduces an additional regulatory risk that may result in exposure to regulatory financial penalties due to the uncertainties associated with such efficiency estimation. Thus, Wharton, et al. (2015, 2016) concluded that on a net basis, decoupling may increase the investment risk of utilities.

Chu and Sappington[14] developed an economic model that investigated under what conditions a utility would provide an economic value maximizing level of energy efficiency services to its consumers. Their investigation is important to our discussion as decoupling is implemented as a tool to incent (or remove the disincentive) utilities to encourage consumers to invest in the optimal level of end-use efficiency resources. In considering the use of decoupling, they found that, generally, decoupling alone is not sufficient to induce utilities to provide the optimal level, that is, enough energy efficiency services. Khazzoom[15,16] found that one problem is that end-use energy efficiency resources cause a rebound effect whereby lower utility bills cause consumers to increase their energy use as they buy more comfort with their bill savings.

Depending on the specific conditions facing a utility, decoupling may not generate a profit motive for utilities to reduce sales through energy or water efficiency. Utilities could be placed in the position of delivering the predicted amount of energy or water savings expected by regulators but possibly without any profit motive other than the avoidance of regulatory penalties for not meeting a goal. This disincentive has become a major topic relative to alternative ratemaking mechanisms, as the growth in electricity sales is currently less correlated with the growth rate in the US GDP relative to the past, with such sales growing more slowly than the general economy in recent years.[17]

Since the US is widely adopting decoupling (revenue caps) whereas the EU is doing the same with price caps, it is an ongoing natural experiment that allows for comparisons of the consumer value and

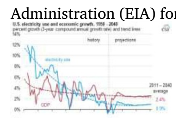
[13] Since multiple types of risk are discussed, we generically define risk as the chance of a disappointment in financial performance.

[14] Chu, L.Y., and D.E.M. Sappington. (2013). Motivating energy suppliers to promote energy conservation. Journal of Regulatory Economics, 49, 227-249.

[15] Khazzoom J.D. (1980). Economic implications of mandated efficiency in standards for household appliances. Energy Journal, 1, 21–39.

[16] Khazzoom J.D. (1987). Energy savings resulting from the adoption of more efficient appliances. Energy Journal, 8, 85–89.

[17] US Energy Information Administration. (2013). Annual Energy Outlook 2013 Early Release US electricity use is expected to experience an annual average growth rate of 0.9% compared with a 2.4% US GDP annual growth rate between 2011 and 2040, according to the US Energy Information Administration (EIA) forecast in 2013, as demonstrated in the EIA graph below:



shareholder value performance between EU price cap utilities and US decoupled utilities. However, since the EU has not adopted decoupling, the data are not available to include EU decoupled utilities in this study.

Since decoupling, as a regulatory policy tool, is being adopted rapidly in the US, Edison Electric Institute, the US electric utility trade association {EEI(2015)}[18] finds that questions arise in regulatory rate proceedings regarding the impacts on the cost of common equity. Due to the importance of this issue and the lack of related literature, we investigate the impact of decoupling on the investor perceived risk of public utilities and resultant cost of common equity.

2. The modeling approach

This paper uses the GCAPM developed by Michelfelder and Pilotte[19] to estimate the impact of decoupling on the public utility cost of common equity[20] . The GCAPM is a financial valuation model recently developed as an alternative to the capital asset pricing model and the dividend discount model for estimating the cost of common equity. Ahern, Hanley, and Michelfelder[21] and as Michelfelder[22] review and apply the GCAPM to estimate public utilities' cost of common equity.

The GCAPM model has fewer restrictions than most financial models. Unlike the CAPM, the GCAPM prices the total risk actually faced by the investor and does not assume that all unsystematic risk is diversified away, which is a key foundation of the standard CAPM.[23] Thus, the priced risk in the GCAPM is based on the level of risk actually faced by the investor, not the risk theoretically imposed by the CAPM. In addition, Fama and French[24] find that the CAPM understates returns and risk, based on a large empirical study of portfolios of common stocks with a continuum of low to high betas. The GCAPM also does not assume or require the efficient markets assumption as does the CAPM.

In the GCAPM, the anticipated risk premium on an asset or common stock depends on the anticipated volatility of that asset's risk premium. The anticipated volatility in the risk premium is driven by current and past risk premia and shocks to the premium. The variances of rates of return are highly correlated with past such variances.

Another property of the model allows us to infer whether decoupling causes a public utility common stock to be a business cycle hedge {Michelfelder and Pilotte (2011)}. This is indicated by the sign of the slope of the risk premium and anticipated volatility. If profits rise or are flat as GDP declines with lower commodity sales and stable revenues, the common stock price could systematically rise when the business cycle is contracting.[25] A public utility with a strong level of decoupling could conceivably experience stable revenues during a contraction in the business cycle. Therefore, utility profits may rise, or at least not fall, when commodity sales fall generated by consumer end-use efficiency and contracting GDP.

To calibrate the GCAPM, we perform a simple test of this property by estimating the model with the risk premium on gold (percent change in the price of gold per troy ounce minus a risk-free rate). Gold is commonly known to be a business cycle and common stock market hedging asset as noted by Hillier, Draper, and Faff[26] . Hillier, Draper, and Faff (2006) show that gold is a common stock market hedge, especially during abnormally high periods of common stock market volatility. Our calibration test results indicate that that the GCAPM model does indeed detect a hedging asset as the slope of the risk premium on its volatility is negative.[27]

The GCAPM can be applied to any asset that is traded in any financial market and therefore can be applied to all traded public utility common stocks. The GCAPM has the added advantage that the decoupling impact on changes in common stock returns as well as the conditional volatility of these returns can be estimated separately within the same model.

Decoupling is expected to lower the variance of the operating cash flows of a public utility due to the increased stability of revenues. The variance of operating cash flows should be driven mainly by the variance of costs[28] Since the volatility of revenues is theoretically equal to zero with decoupling, the covariance of revenues and costs is zero as revenues do not vary, and volatility of *OCF* is purely driven by costs only as *VAR* (R – C) = *VAR (C)*.[29] This is essentially the model used by Moody's (2011)[30] which found that utilities with decoupling experienced a reduction in business risk as measured by the change in the standard deviation of the growth rate in gross profit before and after decoupling.

We also estimate changes in systematic investment risk resulting from decoupling by analyzing the change in the short-term (12-month) CAPM beta (β). This short-term beta, a measure of systematic risk, should be more sensitive to regulatory regime changes, such as, for example, decoupling, relative to the standard betas estimated with five years of data typically employed to assess investment risk. Beta is expected to decline with decoupling.[31]

The only other studies on the impact of decoupling on the utility cost of capital, Wharton, et.al. (2015, 2016)[32],[33] estimated the impact of decoupling on the cost of capital for the overall electric and gas utility industries. They also addressed the issue that decoupled subsidiary utilities may represent substantially less than the entire portfolio of assets reflected in the common stock price of a holding company. Using the standard dividend discount model to estimate the cost of common equity portion of their weighted average cost of capital

[18] EEI, Alternative Regulation for Emerging Utility Challenges: 2015 Update.

[19] Michelfelder, R.A., and Eugene A. Pilotte. (2011). Treasury bond risk and return, the implications for the hedging of consumption and lessons for asset pricing. Journal of Economics and Business, 63, 582-604.

[20] The model is based on generalizing variants of intertemporal capital asset pricing models. The literature discussing the development of the model based on more restrictive versions is voluminous and summarized by Michelfelder and Pilotte (2011) and therefore not repeated here.

[21] Ahern, P., F. J. Hanley, and R.A. Michelfelder. (2011). New approach for estimating of cost of common equity capital for public utilities. Journal of Regulatory Economics, 39, 261-278.

[22] Michelfelder, R.A. (2015). Empirical analysis of the generalized consumption asset pricing model: estimating the cost of common equity capital. Journal of Economics and Business, 80, 37-50.

[23] There is no perfect portfolio that removes all idiosyncratic risk as assumed in the development of the CAPM. Unsystematic risk is reduced but not completely mitigated with a highly diversified portfolio and the standard CAPM understates the cost of common equity as it does not price all risk exposure.

[24] Fama, E., and K. French. (2004). The capital asset pricing model: Theory and evidence. Journal of Economic Perspectives, 18, 25-46.

[25] One of the most effective "energy efficiency tools" to generate energy use reduction is a recession. Although the energy-use-US-GDP correlation has declined, it remains substantially positive {EIA (2013), as shown in the figure in footnote 18 above, www.eia.gov/todayinenergy/detail.php?id=10491}.

[26] Hillier, D., P. Draper, and R. Faff. (2006). Do precious metals shine? An investor's perspective. Financial Analysts Journal, 62, 98-106.

[27] All empirical results on gold are available on request.

[28] Operating Cash Flows (*OCF*) is Revenues (*R*) – Cost (*C*), therefore the variance of *OCF* is $VAR\ (R - C) = VAR\ (R) + VAR\ (C) + 2COV\ (R,C)$.

[29] Therefore, in comparing the variance of operating cash flows with and without decoupling, the $VAR\ (OCF\ with\ decoupling) = VAR\ (C) < VAR\ (OCF\ without\ decoupling) = VAR\ (R) + VAR\ (C) + 2COV\ (R,C)$ as $VAR\ (R) = 0$ and $COV\ (R,C) = 0$ with decoupling and $VAR\ (R) > 0$ and $COV\ (R,C) \neq 0$ without decoupling.

[30] Moody's Investment Services, "Decoupling and 21st Century Ratemaking", Special Comment, November 4, 2011.

[31] Systematic risk is defined as the correlation of an individual common stock's and the market total rates of return

[32] Wharton, J. and M. Vilbert. (2015). Decoupling and the cost of capital. The Electricity Journal, 28, 19-28.

[33] Vilbert, M., J. Wharton, S. Zhang, and J. Hall. (2016). Effect on the cost of capital of ratemaking that relaxes the linkage between revenue and kwh sales, an updated empirical investigation of the electric industry. A Brattle Group Report.

estimates, they regressed this cost of capital on an intensity index of decoupling for each publicly-traded utility common stock to estimate the industry impact. They found no statistically significant impact of decoupling on the cost of capital.

The present study estimates the impact on the cost of common equity of the decoupled firm individually rather than that on an industry as a whole. We use the GCAPM and changes in beta before and after the implementation of decoupling to estimate the impact on risk and the cost of common equity.

3. Methodology

Two versions of the GCAPM model are estimated.[34] Both estimations use a binary variable to reflect the implementation of decoupling for a specific utility with a value of 1 with decoupling and 0 if otherwise.

These results provide separate empirical estimates of the impacts of decoupling on the public utility common stock returns as well as volatility of the returns (risk). As event studies, these and all financial market-based event studies face the question of when the event impacted asset prices, as they can reflect forthcoming events before they are implemented. One example that is relevant for this study is when decoupling implementation was announced in a utility's regulatory decision. We find that using the date of implementation is a conservative approach to estimating the impact as it is most likely the latest date that a decoupling impact would be detected in a common stock price with much of the impact already priced in the asset. However, if a utility's revenues have been decoupled from sales to the extent that revenues are not affected by the business cycle, then the utility's common stock as a hedging asset would be detected in a zero or negative risk-premium-to-volatility slope. Also, if a sufficiently long pre-decoupling time period for observing returns and volatility is available, the change in the post-period should be detected as all of the post-decoupling period returns and volatilities are in a different business risk regime.

4. Data

We perform the empirical work on US utilities only. As discussed in the Introduction, decoupling had not yet been adopted in the EU at the time of this study. The group of US public utility common stocks includes all electric as well as electric and gas combination companies that have 95 % or more of their revenues decoupled and water utility common stocks that have all of their revenues decoupled before 2014. Data for the common stock rates of return are the total monthly rates of return on the common stock of the public utilities from the Center for Research in Security Prices database (CRSP) of the University of Chicago. Data for each public utility common stock include differing pre- and post-decoupling dates and therefore differing rate of return and beta samples. The pre-decoupling data for each common stock include all available past monthly returns data in the CRSP before decoupling for that common stock. Post-decoupling rate of return data for all common stocks end at December 2014 for consistency in the post-decoupling ending period for all utility common stocks. We calculated historical monthly common stock equity risk premiums (monthly common stock returns less the monthly yields on long-term U.S. Treasury Bonds for the selected publicly traded water utilities using common stock returns data from the CRSP database and Morningstar (2015) SBBI® 2015 Market Results for Stocks, Bonds, Bill and Inflation 1926–2015[35] and the Federal Reserve Statistical Release H.15 for long-term Treasury bond yields. The CAPM beta data include all short-term betas available for each public utility common stock that has been decoupled in the CRSP database and ends at 2014. They are available on an annual basis. The CAPM short-term beta is a one-year estimate of beta that approximately involves regressing daily rates of return on the public utility common stock on a market index as shown footnote 31. The standard beta available from financial firm databases such as Value Line Investment Survey or CRSP are 5-year betas based on regressing monthly or weekly common stock rates of return for the past 5 years on a market index. We find that the longer-term beta would be less sensitive to regime changes in risk such as decoupling. We restrict the sample of pre- and post-decoupling betas for each common stock so that the number of beta observations are the same before and after decoupling.

Since the number of data observations has different times series of ranges for each public utility common stock and decoupling occurred on different dates for most utilities, we have developed Table 1 to show each public utility common stock's data date range, that is, the dates and number of risk premium (rate of return minus risk-free rate) observations used to estimate the GCAPM and the total number of betas used for the pre- and post beta comparison. Table 1 also has the date of decoupling for each public utility.

5. Results and discussion

Table 2 presents the public utility common stocks in the study and the empirical results of the GCAPM estimates. The risk-premium-to-volatility slopes re shown along with the decoupling slope in the risk-premium and volatility equations for each electric, electric and gas combination, and water utility common stocks. The decoupling slope in the risk-premium equation will be negative (positive) if the risk premium should decline (rise) and decoupling creates a reduction (increase) in business risk. None of these slope estimates are statistically significant. The decoupling slope in the volatility equation should be negative (positive) if decoupling caused a reduction (increase) in the volatility of the profit of the utilities. Two of the slopes are negative and significant at $p = 0.10$, yet the magnitudes of the slopes are very small.

All of the return-volatility slopes, except for one of the energy utilities are positive and significant, yet none in the water utility group are significant. These results indicate that the energy utility common stocks are not business cycle hedging assets and that their profits are synchronized with the business cycle. The results for the water group may indicate that they are business cycle hedging assets as none are statistically significant. The zero value for the water utility slopes imply that there is no relation between water utility rates of return and the business cycle. Water utility profits are not correlated with the business cycle even in the absence of decoupling. Also, water usage attrition is occurring across the US as households (water consumption per household is declining) due to the use of water-efficient appliances (such as low-flow faucets, showerheads and efficient toilets) and the change per capita water use behaviors to conserve water.

Table 3 presents the pre- and post-decoupling changes in the systematic risk as represented by the short-term CAPM beta for all of the public utility common stocks. Although, the betas drop after the implementation of decoupling, none of the changes in beta are statistically significant using a t-statistic at a $p = 0.05$. Additionally, the standard errors of the betas (σ_{pre} and σ_{post}) show no consistent pattern of increasing or decreasing after decoupling.

Our results do not show any statistically significant impacts of decoupling on the cost of common equity and risk. Therefore, we find no evidence to conclude that decoupling affects investor perceived risk or the cost of common equity. While electric and gas public utility common stocks were not found to be business cycle hedges, we do find that water utility common stocks may be business cycle hedges, or more likely, water usage and revenue simply have no relation with GDP.

Our results are based on the moderate amount of data available to date. Although we would obviously prefer more data than are available

[34] Specifications available on request.

[35] Morningstar® SBBI®. (2015). Market Results for Stocks, Bonds, Bills, and Inflation 1926 - 2014, Appendix A Tables.

Table 1
Data Description for Risk Premiums and Betas.

Electric, Elec. & Gas Comb. Utility	Effective Decoupling Date	Beginning of Measurement Period Returns Data	Total # of Months Return Data	Total Number of Pre- and Post- Annual Beta Observations
Consolidated Edison	10/2007	07/30/02	126	10
Pacific Gas & Electric	01/1983	01/31/53	720	60
Edison International	01/1983	01/31/53	720	60
CH Energy Group	07/2009	01/31/06	84	6
CMS Energy Corp.	05/2010	9/30/07	64	6
Hawaii Electric	12/2010	11/30/08	50	5
Portland General Electric	12/2010	11/30/08	50	6
Idaho Power	03/2007	05/30/01	140	12
Water Utility				
American States Water	1/2002	6/2002	153	12
California Water	1/2009	10/2001	162	12
Connecticut Water	7/2008	10/2002	150	10
Artesian Resources	11/2008	6/1996	226	12

Table 2
GCAPM Estimation Results.

Electric, Elec. & Gas Comb. Utility	Risk premium to volatility slope	Change in risk premium to volatility slope with decoupling	Decoupling Impact on Volatility Decoupling
Consolidated Edison	1.460***	0.004	−0.000
Pacific Gas & Electric	1.781***	0.001	−0.001
Edison International	1.379***	0.003	0.000
CH Energy Group	2.094***	0.004	−0.000
CMS Energy Corp.	1.440***	0.011	−0.000
Hawaii Electric	1.607***	0.004	−0.000*
Portland General Electric	0.461	0.010	−0.000
Idaho Power	1.939***	0.003	−0.000
	Water Utility		
American States Water	0.596	0.011	0.000
California Water	0.525	0.004	−0.000
Connecticut Water	−1.008	0.009	0.000
Artesian Resources	3.006	−0.004	−0.002*

Table 3
Changes in Systematic Risk from Decoupling.[a]

Electric, Elec. & Gas Comb. Utility	Mean β_{PRE}	Mean β_{POST}	σ (β_{PRE})	σ (β_{POST})	t-Statistic
Consolidated Edison	0.608	0.427	0.172	0.064	−1.329
Pacific Gas & Electric	0.522	0.535	0.174	0.373	0.112
Edison International	0.588	0.582	0.199	0.294	−0.051
CH Energy Group	0.680	0.401	0.279	0.326	−0.759
CMS Energy Corp.	0.758	0.559	0.198	0.140	−0.815
Hawaii Electric	0.619	0.570	0.253	0.155	−0.171
Portland General Electric	0.637	0.658	0.069	0.052	−0.151
Idaho Power	0.905	0.728	0.251	0.125	−0.818
Mean	0.670	0.560			
Water Utility					
American States Water	0.975	0.623	0.535	0.279	−1.430
California Water	1.192	0.520	0.544	0.257	−2.735***
Connecticut Water	0.664	0.502	0.235	0.176	−1.232
Artesian Resources	0.075	0.146	0.100	0.161	0.909
Mean	0.434	0.475			

[a] Beta is the annual year-ending beta from the CRSP database. The data timeframe is different for each utility with an equal number of annual pre- and post-decoupling beta data observations for the specific stock in the CSRP database and ends in 2014. Each single beta was estimated with one year of daily rate of return data. See Table 1 and footnote 32. ***, **, * refers to statistical significance at 0.01, 0.05, and 0.10 respectively.

at this juncture, there is no time to wait for a larger volume of data as regulators and utilities have been and are implementing policy now as if decoupling does reduce business risk and, thus, the costs of capital without any evidence that it does. This paper serves as an early warning signal, albeit with the limited evidence that is available.

6. Conclusion and policy implications

We conclude that decoupling has no statistically measurable impact on the cost of common equity or business risk based on our empirical analysis for electric, electric and gas, and water utility common stocks. Some researchers may view this result as a “non-result.” This is an important finding as it is consistent with the empirical findings of Vilbert, et al. It is also important for policy globally as decoupling is considered as a potential reducer to risk and the cost of common equity by regulators and public utilities in the US based on intuition, without any empirical evidence.

Moody’s (2011) finds a reduction in business risk as measured by the change in the variability of gross profit after decoupling but did not estimate the impact on the cost of common equity. Moody’s (2011) did find that electric utilities were somewhat reluctant to adopt decoupling as electric utility executives anticipated that growth in sales would return after the steep recession that ended with the business cycle trough in June 2009 as identified by the National Bureau of Economic Research[36] . Since the US business cycle expansion post-June 2009, electricity sales have remained almost flat, which may have caused the change in sentiment toward decoupling by electric utility executives. Growth in a utility’s commodity sales above the level used to design regulated rates would increase the profit and rate of return on common equity. The US investor-owned electric utility industry also expected that the adoption of decoupling would cause state public utility regulators to reduce their allowed rate of return under the notion that it reduces risk. Moody’s (2011) was written soon after the recession had ended, but the anticipated growth in sales has not materialized after more than ten years into the US business cycle expansion. A few years after the Moody’s (2011) study, in a more recent report, the EEI found a change in sentiment {EEI (2015)} that electric utilities favor decoupling and that it has become more widespread across the US.

Although we conclude that decoupling has no statistically significant impact on investor perceived risk and the cost of common equity, this does not mean necessarily that decoupling has no impact on the perceived risk and the cost of common equity of public utilities. We find that it cannot be isolated and estimated, given the many other factors affecting investor perceived risk. For many electric utilities, some current major risk drivers are flat or declining sales from customer-owned solar projects and energy efficiency resources; the

[36] National Bureau of Economic Research. (2018). NBER.org.

requirement to buy back excess customer generated electric from renewable resources at full retail rates (net metering); increasing requirements in the proportion of a utility's sales that have to be generated from renewable energy, causing larger purchases of renewable energy credits (known as renewable portfolio standards that have been adopted by many states and across Europe); increasingly stringent environmental regulations on coal plants; and the impact of falling and low natural gas prices on the competitiveness of existing coal and nuclear plants.

For water utilities, we find their common stocks to be moderate business cycle hedges (no correlation with the business cycle rather than a strong negatively correlated hedge). Since water utility sales are declining on a per capita basis and unassociated with the business cycle, decoupling may provide financial protection if water revenues decline. To the extent that there is positive growth in the number of water utility customers that offsets the declining per capita consumption, total revenues and sales may not be falling. The impact of decoupling on water utility investment risk and cost of common equity was not able to be detected in this study. This is the first study on decoupling in the water utility industry and provides an area for future research.

Another explanation for the lack of detection of a change in risk or the cost of common equity from decoupling is that risk may be created with the implementation of decoupling and the net impact may not be clear as an increase or decrease in risk as Vilbert, et al. They find that the implementation of decoupling is a new and alternative regulatory regime that may be a new source of regulatory risk for the utility. Finally, as discussed in detail in the Introduction above, volume risk, that is, the fundamental nature of the business and business risk, is not alleviated by changing the reward mechanism, and attempts to do so may increase risk and the cost of common equity. The point is that there are cogent theoretical and practical bases to expect that decoupling increases or decreases risk, so it is problematic to develop an *a priori* hypothesis to test a one-way directional impact of risk and return from decoupling.

Therefore, we do not recommend that public utility regulators in the US or elsewhere reduce common equity cost rates in the presence of decoupling mechanisms based on the assumption of reduced risk. The impact is *de minimis* and not statistically significant amongst all of the other investor perceived risk factors affecting the market prices of public utility common stocks. While an alternative research approach may attempt to isolate the impacts of other individual risk factors on the cost of common equity and risk, making for a long regression equation, we cannot detect a statistically significant signal of decoupling on the cost of common equity or volatility. As a contrast, for example, the risk and cost of common equity impact of owning nuclear power generation assets (versus no nuclear assets) has a measurable impact on investors' returns, risk and cost of common equity without attempting to isolate the myriad of other risk variable impacts. Decoupling as a regulatory policy mechanism to encourage public utilities to provide resources and funding to their consumers to conserve electricity, natural gas, and water (therefore also wastewater flows) has no *measurable* impact on the investment risk and the cost of common equity (either up or down). As a policy prescription, public utility regulators should not adjust the allowed rate of return which affects the public utility's rates as a spillover impact of using decoupling to promote environmental policy.

Finally, the US may be further ahead in adopting rate mechanisms that address energy and water efficiency due to its long-term lag relative to Europe in the efficient use of energy and water and the recent "necessity-is-the-mother-of-invention" US driver of energy and water efficiency. European and other global regulators should proceed slowly in adopting decoupling and assuming that decoupling reduces risk as there is no empirical evidence to date that it does.

An extension of this research could evaluate risk premiums or discounts in bond yields as there are many more investor-owned utilities which have outstanding bonds relative to those that have their own publicly traded common stock due to consolidation in the utility industry in the US. For example, Exelon is the holding company of six utilities whose stocks were publicly traded on the New York Stock Exchange. They are Atlantic City Electric, Baltimore Gas and Electric, Commonwealth Edison, Delmarva Power and Light, Philadelphia Electric and Potomac Edison Power. Another future extension could focus on decoupling when some EU investor-owned utilities and regulators, inevitably, adopt decoupling should it prove to substantially encourage more conservation in the US. An investigation of hedging costs and savings, risk impacts, and effects on profits with and without decoupling may shed more light on the topic. More research is also needed on water decoupling as this is the first study known to date on the topic involving cost of capital and risk. Lastly, a comparison that separates consumer and shareholder value creation and investigating the impacts on conservation from price and revenue caps is another extension of this paper for future research.

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Decoupling impact and public utility conservation investment

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ABSTRACT

Public utilities and regulators are implementing various forms of regulatory mechanisms that decouple revenues from commodity sales to remove a disincentive or create an incentive for utilities to invest in and encourage consumers to conserve electricity, natural gas and water. A major question is whether such regulatory mechanisms affect investor-perceived risk, the cost of common equity and the utility rates of such commodities. This is an important question as regulators in the US are and have been considering the impact of decoupling on investment risk and therefore the cost of common equity in rate proceedings. This matter is also important for regulators globally as they consider decoupling as a policy initiative in setting rates and rate of return. Currently, decoupling is primarily a US ratemaking policy for energy and water utilities as are price caps in Europe. Empirical testing, based on the available data in the US, consistently demonstrates that decoupling has no statistically measurable impact on risk and the cost of common equity. Therefore, at this juncture, policy is moving ahead, at least in the US, without empirical evidence on whether it does have impact on risk and return.

1. Introduction

Beginning in the late 1970s, US policymakers, legislators, regulators and public utilities began to focus on reducing consumers' demand for energy rather than increasing supply. This was mainly a reaction to the oil supply shock in the US in the early 1970s, which began with the National Energy Conservation Act of 1978. Europe was already much more efficient in the use of energy by the 1970s as the BTU content of GDP of many European countries was a substantially small fraction relative to the US.

More recently in the US, regulatory policy has required water utilities to encourage the reduction in water use by their consumers. The US and European utility industries seem to observe each other's experiments in decoupling and price caps before adopting such alternative ratemaking policy movements. Price cap regulation, where utility prices are allowed to rise to a cap set by an inflation index minus a total factor productivity offset that reflects potential cost savings (known as *RPI – X*), was implemented decades ago for British utilities. Only afterward was it adopted by many other utilities in Europe (EU). However, it has largely not been adopted in the US as very few utilities are under price cap regulation except for telecommunications local exchange carriers. On the other hand, decoupling, which effectively disassociates revenue levels from commodity (electric, gas or water) sales has been sweeping across the US in the last two decades for energy and water utilities, while being not adopted in Europe.

Campini and Rondi (2010) show that alternative rate mechanisms in the EU have been in the form of price caps to promote efficient investment and operating expenditures. There is no mention in that article of decoupling. They also point out that since many utilities in the EU are government owned there has not been any major adoption of alternative regulatory rate making methods across the utility industry as government utility rates are not regulated. Therefore, this study is limited to analyzing decoupling in the US, as it is still almost exclusively a regulatory tool implemented in the US.

A major financial impediment preventing investor-owned utilities from encouraging conservation of energy and water usage and sales is the profit disincentive associated with subsequent revenue and profit reductions. Therefore, various regulatory policy mechanisms have been developed to provide utilities with a financial incentive, or, at least, remove the disincentive to utilities to encourage energy and water efficiency. Some mechanisms have been the inclusion of conservation expenditures in rate base so the such expenditures earn a return. Other mechanisms allow for a profit incentive equal to a proportion of the life cycle of net benefits, as well as rate of return premiums for meeting or exceeding conservation goals. Increasingly, revenues are being decoupled from sales volumes so that reductions in sales volumes will

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potentially stabilize profits rather than reduce them.[1] Decoupling revenues from sales volumes was first implemented in California in 1982 and in New York in the 1980s. Although decoupling did not gain momentum outside of California and New York for decades afterward, it has recently been implemented in various state regulatory jurisdictions across the US for electric, natural gas, and water public utilities. Fig. 1 is a map depicting the extent of decoupling across the US developed by the National Resources Defense Council (2018). Although it shows the extent of decoupling across the US for electricity and natural gas utility industries, it does not show the same for water/wastewater utility industries. Fig. 1 shows that as of August 2018, 26 states have adopted gas decoupling (compared with 20 in 2013) and 17 have adopted electricity decoupling (compared with 14 in 2013).

The types of decoupling generally fall into three categories: fixed and variable mechanisms, lost revenue recovery from commodity sales reductions due specifically to energy or water efficiency programs, and fixed revenue true-up mechanisms. Fixed and variable rate mechanisms have a high fixed rate component that may or may not include a set maximum volume of the commodity included in the fixed rate and the variable component is the rate for partial or all volume use. The fixed rate is meant to cover all or most fixed costs. They are rarely used in the electric or gas utility industries but are frequently used for water utilities. Lost revenue recovery mechanisms allow the utility to collect the revenue lost directly from the specific sales reductions due to energy or water efficiency programs. True-up mechanisms set a fixed overall level of revenues and the utility can recover a shortfall in revenues from the set level in higher rates. Nadel and Herndon (2014) discuss the future of the energy utilities industries and the role that decoupling as a form of alternative ratemaking may play in that future. Also, see Carter (2001), Cavanaugh (2013), Eto et al. (1997) and the American Council for an Energy Efficient Economy and Natural Resource Defense Council websites for discussion on the trends, theory and implementation of decoupling and various decoupling mechanisms.

One key consideration in many US rate proceedings and policy discussions is the impact of decoupling on the investment risk of a public utility and its cost of common equity (and therefore the allowed rate of return set by regulators). Since decoupling disassociates revenues with sales volumes, the intended impact is that it generates an increasingly stable and non-declining level of revenues and net income if sales do decline. Therefore, the public utility is expected to be perceived by investors as having lower investment risk, which would lead to a lower cost of common equity capital, i.e., the investor required return.

Decoupling can also be viewed as exacerbating investment risk rather than decreasing it. To the extent that investors are concerned about a changing regulatory regime, uncertainty about the measurement of the savings impacts of conservation programs, partially implemented or gamed mechanisms, to name a few potential issues associated with such an alternative ratemaking mechanism, may exacerbate investors' perceived risk and the cost of common equity.

Decoupling is implemented with the intention to reduce or eliminate volume risk and therefore potentially the cost of common equity as stated above. If the utility hedges volume risk due to weather, which is the most likely cause of demand shocks to electric, gas or water commodities, hedging derivatives[2] allow the utility to insure such risk. If the utility hedges most of the commodity demand risk while meeting demand regardless of compensation mechanisms, the risk may fall if the volume risk is systematic. Whether such weather risk is systematic or not is questionable as weather shocks do not affect most common stocks in a highly diversified portfolio nor the business cycle that drives the systematic risk of a market portfolio. It may not be systematic even within a utility-only portfolio as weather patterns can be diversified away with geographical diversification. If weather happens to have a systematic effect on the risk of the public utility common stock, it is conceivable that cost-effective hedges may reduce risk and the cost of common equity. Should the utility hedge risks that do not materialize into an adverse effect such as a demand shock, they incur costs to do so, and the hedges do not payoff. That is, they spend too much on hedged positions or insurance or take title to commodity that they cannot sell, such as with a take-or-pay contract, thus facing increased risk, costs and higher costs of common equity. Therefore, volume risk is not actually alleviated with decoupling. Essentially, the question is that although the risk of the business is not changed by reward mechanisms, as demand shocks (positive or negative) still occur, do investors perceive, as do some regulators and utility management, that decoupling reduces risk? A change in the reward structure does not change the fundamental riskiness of a firm. It is the investors' perceived risk that affects the cost of common equity. This would not seem to occur in an efficient market, but it is not so obvious that financial markets are efficient.

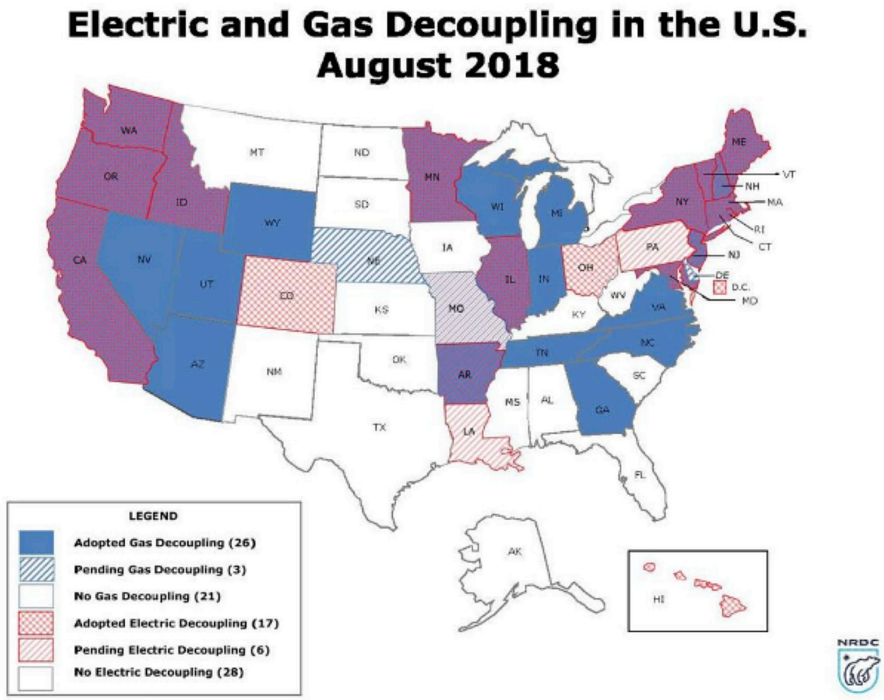
An efficient market is one of a number of assumptions that has been relaxed in the derivation of the generalized consumption asset model (GCAPM) used in this paper. As one example of inefficiency, cash flows generate the fundamental value of a firm, yet the best predictor of common stock prices statistically is earnings per share growth rates, not cash flow per share growth. Investors seem to erroneously price common stocks with earnings, not cash flow based on their perceptions of what affects common equity financial value.

The topic of this paper has been the subject of only a few empirical investigations so far by Wharton and Vilbert (2015) and Vilbert et al. (2016). Moody's (2011) has estimated the change in business risk and credit metrics due to decoupling, but not the impacts on the cost of capital. There are no empirical studies on water utilities such as those performed herein.

Wharton and Vilbert (2015) developed an index of decoupling exposure for public utility and utility holding company common stocks and estimated the after-tax weighted average cost of capital (ATWACC) using the dividend discount model to estimate the cost of common equity. They regressed the ATWACC on an index of decoupling intensity for each public utility in their sample and observed the slope to

[1] In response to the challenges to achieving the allowed return on common equity due to expected significant capital expenditures to repair and replace utility infrastructure, as well as declining per capita commodity consumption, the National Association of Regulatory Utility Commissioners (NARUC) recommends that regulators carefully consider and implement appropriate ratemaking measures so that water and sewer utilities have a reasonable opportunity to earn their allowed rate of return on common equity. Decoupling, or revenue adjustment stabilization mechanisms (RAM) separate rates/revenues from electricity, gas or water volumes sold. Such mechanisms address the effects of the more efficient use of the commodity and declining per capita consumption, for water, and to a lesser extent, electricity, while maintaining the financial soundness and viability of the utilities. With RAMs, utilities are made whole for revenue shortfalls from allowed revenues used to design rates, which generally result from weather and conservation efforts by customers. RAMs allow for the recovery/crediting of differences between actual and allowed quantity charge revenues. RAMs seem to be effective in mitigating the effects of regulatory lag and improving utilities' opportunities to earn their allowed returns on common equity while upgrading infrastructure, ensuring safe and reliable service, removing the incentive to sell more commodity, and helping to protect valuable natural resources. However, in base rate cases for utilities that have such mechanisms, the question often arises as to whether and to what extent the presence of such mechanisms reduces the utility's investment risk as well and to what extent such a perceived or actual reduction in risk should be reflected in the allowed return on common equity.

[2] Water derivatives, although not traded in markets as are gas and electricity futures and forwards, are created through private contracts. Some water distribution systems are interconnected to others and have various contracting structures for buying water if a demand shock should cause the need for more water that the incumbent system cannot supply. Some sewer systems have similar contracts to transfer excessive wastewater flows to another utility's treatment plant if their own capacity reaches its limit.



	2013		2018	
	Utilities	States	Utilities	States
Gas	49	20	64	26
Electric	24	14	41	17
Total	73	25	105	32

Fig. 1. Trend in Energy Utility Decoupling in the US. Source: https://www.nrdc.org/resources/gas-and-electric-decoupling, accessed March 31, 2019

estimate the impact. Although the slope of the regression is negative, it is not statistically significant. They concluded that decoupling has no statistically significant measurable impact on the public utility cost of common equity. They found that decoupling may reduce revenue volatility, but it may not reduce investment risk. They find that it may actually exacerbate risk as decoupling regulatory policy is viewed as a new and uncertain regime and may be used to promote other regulatory policy goals and create regulatory risk.[3]

Reductions in peak loads and the commodity sales impacts of consumer energy or water efficiency measures are difficult and expensive to estimate. This difficulty introduces an additional regulatory risk that may result in exposure to regulatory financial penalties due to the uncertainties associated with such efficiency estimation. Thus, Wharton and Vilbert (2015) concluded that on a net basis, decoupling may increase the investment risk of utilities.

Chu and Sappington (2013) developed a social welfare model that investigated under what conditions a utility would provide a welfare maximizing level of energy efficiency services to its consumers. Their investigation is important to our discussion as decoupling is implemented as a tool to incent utilities to encourage consumers to invest in the optimal level of end-use efficiency resources. In considering the use of decoupling, Chu and Sappington (2013) found that, generally, decoupling alone is not sufficient to induce utilities to provide the socially optimal level, that is, enough energy efficiency services. One problem is that end-use energy efficiency resources cause a rebound effect {Khazzoom (1980, 1987)} whereby lower utility bills cause consumers to increase their energy use as they buy more comfort with the savings.

Chu and Sappington (2013) also discuss that, if the price of electricity is above the private marginal cost (in contrast to social marginal cost), falling sales reduce the utility's profits.[4] Since public utility ratemaking uses average cost to set rates, this is a highly unlikely occurrence to find price above marginal cost. Depending on the specific conditions facing a utility, decoupling may not generate a profit motive for utilities to reduce sales through energy or water efficiency. Utilities could be placed into the position of delivering the predicted amount of energy savings expected by regulators but possibly without any profit motive other than the avoidance of regulatory penalties for not meeting a goal. This disincentive has become a major topic relative to alternative ratemaking mechanisms, as the growth in electricity sales is less correlated with the growth rate in the US GDP relative to the past, with such sales growing more slowly than the general economy has been in recent years.[5]

Brennan (2010) developed a social welfare model to derive conditions under which utilities would be incented to provide energy efficiency services, showing that decoupling must separate revenues from the generation of electricity and not just revenues and sales from the

[3] Since multiple types of risk are discussed, we generically define risk as the chance of a disappointment in financial performance.

[4] The key problem with the over-use of utility services is that public utility pricing is based on average versus marginal cost pricing. Utility services have an excess demand (over-consumed) and end-use efficiency resources have an excess supply (under-consumed) with general equilibrium not attained. The authors of this study are hard-pressed to find where the actual price of electricity is above private marginal cost.

[5] US electricity use is expected to experience an annual average growth rate of 0.9% compared with a 2.4% US GDP annual growth rate between 2011 and 2040, according to the US Energy Information Administration (EIA) forecast in 2013, as demonstrated in the EIA graph below.

distribution of electricity, leading to a highly complex form of electricity pricing regulation, rather than just the simpler separation of sales to the consumer and the related revenues collected. Brennan (2010a) compared incentive regulation using price caps versus decoupling. His paper analyzed the difference between separating profits from management decision-making and incentive-based regulation in the form of price caps which are meant to promote better input decision-making than rate of return regulation that provides an opportunity to earn a set rate of return, somewhat regardless of the outcomes of input choice decision-making. Brennan (2010a) concluded that utilities will encourage energy savings or more usage under price caps depending upon whether the price is below or above marginal cost, respectively.

Since the US is widely adopting decoupling (revenue caps) whereas the EU is doing the same with price caps, it is an ongoing natural experiment that allows for comparisons of the consumer surplus and shareholder value performance (collectively, social welfare) from EU price cap utilities and US decoupled utilities. Since the EU has adopted price caps and US has adopted decoupling, the data are not available to include EU decoupled utilities in this investigation.

Since decoupling, as a regulatory policy tool, is being adopted rapidly in the US {Edison Electric Institute, the US electric utility trade association, EEI (2015)}, questions arise in rate proceedings regarding the impacts on the cost of common equity. Due to the importance of this issue and the lack of related literature, we investigate the impact of decoupling on the investor perceived risk of public utilities and resultant cost of common equity. The next section discusses the models that are the basis of the analysis. Section 3 discusses the empirical methodology. Section 4 describes the data. Section 5 discusses the results and Section 6 provides concluding remarks, policy recommendations and areas for future research.

2. The modeling approach

This paper uses the GCAPM developed by Michelfelder and Pilotte (2011) to estimate the impact of decoupling on the public utility cost of common equity. The model is based on generalizing variants of intertemporal capital asset pricing models. The literature discussing the development of the model based on more restrictive versions is voluminous and summarized by Michelfelder and Pilotte (2011) and therefore not repeated here. The GCAPM was empirically applied by Michelfelder and Pilotte (2011) to the full spectrum of assets on the US Treasury yield curve. The GCAPM is a financial valuation model recently developed as an alternative to the CAPM and the dividend discount model for estimating the cost of common equity. Ahern et al. (2011) and as Michelfelder (2015) review and apply the GCAPM to estimate public utilities' cost of common equity.

The GCAPM model has the following characteristics. It does not have restrictions on the coefficient of risk aversion in investors' utility function as do most models. It allows for a negative relation between the rate of return and volatility.[6] This relation will occur for assets with prices that move in the opposite direction of the business cycle. Unlike the CAPM, the GCAPM prices the total risk actually faced by the investor and does not assume that all unsystematic risk is diversified away, which is a key foundation of the standard CAPM. There is no perfect portfolio that removes all idiosyncratic risk as assumed in the development of the CAPM. Unsystematic risk is reduced but not completely mitigated with a highly diversified portfolio and the standard CAPM understates the cost of common equity as it does not price all risk exposure. The priced risk in the GCAPM is based on the level of risk actually faced by the investor, not the risk theoretically imposed by the CAPM. Fama and French (2004) find that the CAPM understates returns and risk, based on a large empirical study of portfolios of common stocks with a continuum of low to high betas. The GCAPM also does not assume or require the efficient markets assumption as does the CAPM.

Ahern et al. (2011) find that the CAPM generates lower costs of common equity than the GCAPM. Michelfelder (2015) applied the GCAPM to estimate the cost of common equity to public utilities concluding that the CAPM does not price all risk faced by the investor and that the CAPM understates the cost of common equity for public utilities. The GCAPM is specified as:

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{vol_t[M_{t+1}]}{E_t[M_{t+1}]} vol_t[R_{i,t+1}] corr_t[M_{t+1}, R_{i,t+1}], \tag{1}$$

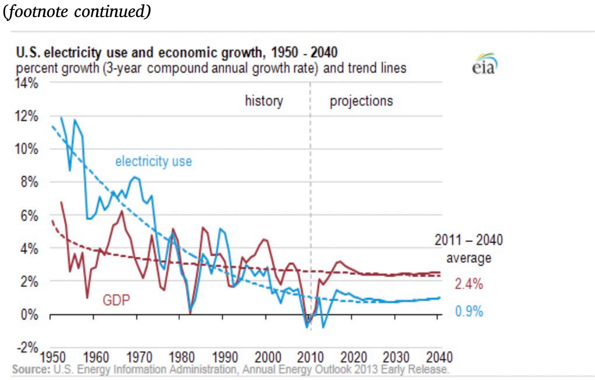
where the anticipated risk premium on an asset *i* depends on the conditional volatility of the asset; $R_{i,t+1}$ is the ex ante return on asset *i*; $R_{f,t}$ is the rate of return on a risk-free asset at time *t*; M_{t+1} is the stochastic discount factor (SDF); vol_t is the conditional volatility of the rate of return; and $corr_t$ is the conditional correlation coefficient. The SDF is the intertemporal marginal rate of substitution in consumption, which is the ratio of expected future marginal utility to the current marginal utility of consumption. This is an important factor to discuss as this model specification allows for the empirical estimation to determine if decoupling results in more stable revenues for utilities relative to changes in the business cycle. If this holds true for a utility during a recession, then investment in the common stock of public utilities could be a business cycle hedge. The SDF is:

$$M_{t+1} = \left(\frac{1}{1+k}\right)\frac{U_{c,t+1}}{U_{c,t}}, \tag{2}$$

where the U_c's are the marginal utilities of consumption and k is the discount rate for the period from t to $t+1$. The ratio M_{t+1} rises if expected future consumption falls below the current level due to the standard concave (to the origin) shape of investors' consumption utility function. This property allows the model to accommodate the business cycle (represented by consumption expenditures) hedging property of a given asset.

If the conditional volatility of intertemporal consumption, or consumption risk, rises, investors will price a greater risk premium into the asset. The sign of the relation between risk premium and its conditional volatility is defined by the correlation ($corr_t$) of the risk premium and the SDF. The sign of the risk premium-to-volatility relation is opposite to the sign of the correlation of the asset return and the ratio of the marginal utilities. A decline in business cycle consumption increases investors' marginal utility. An asset that generates positive returns

(*footnote continued*)



[6] It seems counterintuitive, yet some investors are willing to pay (give up return) for more volatility in an asset's return rather than less, if the pattern of that volatility is desired by those investors. Some researchers confuse risk and volatility as synonymous. For example, gold returns have a tendency to spike upward during recessions and downturns in stock markets. Thus, gold can hedge the downturn in an investor's portfolio and offset the reduction in income from employment. **S**ystematic upward spikes in gold prices increase volatility. Such increases in volatility are generally associated with reductions in the market returns to gold. Such assets with negative relations among returns and volatility are business cycle hedges.

when the business cycle is in a contraction with falling consumption, is a business cycle hedge. Therefore, a negative risk premium-to-volatility slope identifies the asset as a business cycle hedge.

This property allows us to infer whether decoupling causes a public utility common stock to be a business cycle hedge. If profits rise or are flat as GDP declines with lower commodity sales and stable revenues, the common stock price could systematically rise when the business cycle is contracting.[7] A public utility with a strong level of decoupling would conceivably experience stable revenues during a contraction in the business cycle. Therefore, utility profits may rise, or at least not fall, when commodity sales fall generated by consumer end-use efficiency and contracting GDP.

To calibrate the GCAPM, we perform a simple test of this property by estimating the model with the risk premium on gold (percent change in the price of gold per troy ounce minus a risk-free rate). Gold is commonly known to be a business cycle and common stock market hedging asset {Hillier et al. (2006)}. The correlation coefficient between the quarterly percent changes in the price of gold and real GDP (data are publicly available from the St. Louis Federal Reserve Database) from 1968 to 2017 is −0.058. Hillier et al. (2006) show that gold is a common stock market hedge, especially during abnormally high periods of common stock market volatility. We used the daily and monthly US gold commodity cash price data and futures price data to estimate the GCAPM. The risk-premium-to-volatility slope "α" (see footnote 10) is either negative and significant or insignificant using daily and monthly data and many rolling time frames for estimation. These calibration test results for the GCAPM show that the model does detect a hedging asset.[8]

The GCAPM can be applied to any asset that is traded in any financial market and therefore can be applied to all traded public utility common stocks. The GCAPM has the added advantage that the decoupling impact on changes in common stock returns as well as the conditional volatility of these returns can be estimated separately within the same model using the GARCH-in-Mean (GARCH-M) method initially developed for asset model estimation. The GARCH-M method is discussed in the next section.

Decoupling is expected to lower the variance of the operating cash flows of a public utility due to the increased stability of revenues {Moody's (2011)}. The variance of operating cash flows should be driven mainly by the variance of costs as follows: Operating Cash Flows (*OCF*) is Revenues (*R*) – Cost (*C*), therefore the variance of *OCF* is *VAR (R-C) = VAR (R) + VAR (C) + 2COV (R,C)*. Since the volatility of revenues is theoretically equal to zero with decoupling, the covariance of revenues and costs is zero as revenues do not vary, and volatility of *OCF* is purely driven by costs only as *VAR (R-C) = VAR (C)*. Therefore, in comparing the variance of operating cash flows with and without decoupling, the *VAR (OCF with decoupling) = VAR (C) < VAR (OCF without decoupling) = VAR (R) + VAR (C) + 2COV (R,C)* as *VAR (R) = 0* and *COV (R,C) = 0* with decoupling and *VAR (R) > 0* and *COV (R,C) ≠ 0* without decoupling. This is essentially the model used by Moody's (2011) which found that utilities with decoupling experienced a reduction in business risk as measured by the change in the standard deviation of the growth rate in gross profit before and after decoupling.

We also estimate changes in systematic investment risk resulting from decoupling by analyzing the change in the short-term CAPM beta. This short-term beta (12-month), a measure of systematic risk, should be more sensitive to regime changes for a common stock relative to the standard betas estimated with five years of data typically employed to assess investment risk. Beta is expected to decline with decoupling.[9]

The only other studies on the impact of decoupling on the utility cost of capital, Wharton and Vilbert (2015), estimated the impact of decoupling on the cost of capital for the overall electric and gas utility industries. They also addressed the issue that decoupled utilities may represent substantially less than the entire portfolio of assets reflected in the common stock price of a holding company. Using the standard dividend discount model to estimate the cost of common equity portion of their weighted average cost of capital estimates, they regressed this cost of capital on an intensity index of decoupling for each publicly-traded utility common stock with a panel-data regression to estimate the industry impact. They found no statistically significant impact of decoupling on the cost of capital.

The present study estimates the impact on the cost of common equity of the decoupled firm individually rather than that on an industry as a whole. We use the GCAPM and changes in beta before and after the implementation of decoupling to estimate the impact on risk and the cost of common equity.

3. Methodology

The GCAPM is estimated with the GARCH-M method.[10] GARCH-M specifies the conditional risk premium as a linear function of its conditional volatility, which is the specification of the GCAPM in equation (1). Since the returns data contains ARCH effects (available on request), another benefit of using GARCH-M is that it improves the efficiency of the estimates. Engle et al. (1987) developed the GARCH-M method and used it to estimate the relation between US Treasury and corporate bond yield risk premiums and their volatilities.

Two versions of the GCAPM-GARCH-M model are estimated. The first estimation includes a binary variable that reflects the implementation of decoupling for the specific utility ($D_i = 1$ if decoupled, 0 otherwise) in the risk premium equation only and the volatility equation the same:

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \alpha_{i,D}D_{i,t} + \varepsilon_{i,t+1} \tag{3}$$

where "αi, D" is an estimate of the decoupling impact on the risk premium.

The second estimation has the same variable in the volatility equation of the GARCH-M model only and the return equation does not (as shown in footnote 10 in the second set of equations):

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \beta_{i,D}D_{i,t} + \eta_{i,t+1} \tag{4}$$

[7] One of the most effective "energy efficiency tools" to generate energy use reduction is a recession. Although the energy-use-US-GDP correlation has declined, it remains substantially positive {EIA (2013), as shown in the figure in footnote 4 above, www.eia.gov/todayinenergy/detail.php?id=10491}.

[8] All empirical results on gold are available on request.

[9] Systematic risk is defined as $\beta_i = \rho_{i,m}\ \sigma_i/\sigma_m$, where $\rho_{i,m}$ is the correlation coefficient of the individual stock (i) and the market (m) total rates of return and σ_i and σ_m are the standard deviations of the individual stock and market returns, respectively. Defining variables with superscript "D", to denote decoupling, σ_i^D and $\rho_{i,m}^D$ should be lower as the volatility of the utility's returns are lower with decoupling and the utility's return has a lower correlation with the market return as the utility's revenues and profits are decoupled from the business cycle. Therefore systematic risk is lower with decoupling and defined as $\beta_i^D = \rho_{i,m}^D\ \sigma_i^D/\sigma_m$. Therefore, β_i^D is less than β_i as.

$$\rho_{i,m}^D\sigma_i^D/\sigma_m^D \ < \ \rho_{i,m}\sigma_i/\sigma_m$$

[10] The GCAPM was estimated with the GARCH-M method. The estimated models are.

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \alpha_{i,D}D_{i,t} + \varepsilon_{i,t+1}$$

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \eta_{i,t+1},$$

And $R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \varepsilon_{i,t+1}$

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \beta_{i,D}D_{i,t} + \eta_{i,t+1}.$$

where "βi, D "is an estimate of the decoupling impact on the volatility of the risk premium.

These specifications provide separate empirical estimates of the impacts of decoupling on conditional public utility common stock returns and conditional volatility. As event studies, these and all financial market-based event studies face the question of when the event impacted asset prices. Asset prices can reflect forthcoming events before they are implemented. One example that is relevant for this investigation is when decoupling implementation was announced in a utility's regulatory decision. We find that using the date of implementation is a conservative approach to estimating the impact as it is most likely the latest date that a decoupling impact would be detected in a common stock price and much of the impact may already have been priced in the asset. However, if a utility's revenues have been decoupled from sales to the extent that revenues are not affected by the business cycle, then the utility's common stock as a hedging asset would be detected in a zero or negative alpha. Also, if a sufficiently long pre-decoupling time period for observing returns and volatility is obtained, the change in the post-period should be detected as all of the post-decoupling period returns and volatilities are in a different business risk regime.

4. Data

We perform the empirical work on US utilities only. As discussed in the Introduction, decoupling has not been adopted in the EU. EU investor-owned utilities and their regulators have widely adopted price cap regulation, an alternative form of regulation to rate-base-rate-of-return regulation to promote expense and investment efficiency, but not necessarily to encourage utility expenditure on consumer end-use energy and water efficiency. The group of US public utility common stocks includes all electric and gas combination companies that have 95% or more of their revenues decoupled and water utility common stocks that have all of their revenues decoupled before 2014. Data for the common stock rates of return are the total monthly rates of return on the common stock of the public utilities from the Center for Research in Security Prices database (CRSP) of the University of Chicago. Data for each public utility common stock include differing pre- and post-decoupling dates and therefore differing rate of rate and beta samples. The pre-decoupling data for each common stock include all available past monthly returns data in the CRSP before decoupling for that common stock. Post-decoupling rate of returns data for all common stocks end at December 2014 for consistency in the post-decoupling ending period for all utility common stocks. We calculated historical monthly common stock equity risk premiums monthly common stock returns less the monthly yields on long-term U.S. Treasury Bonds for the selected publicly traded water utilities using common stock returns data from the CRSP database and Morningstar (2015) SBBI® 2015 Market Results for Stocks, Bonds, Bill and Inflation 1926–2015 and the Federal Reserve Statistical Release H.15 for long-term Treasury bond yields. The CAPM beta data include all short-term betas available for each public utility common stock that has been decoupled in the CRSP database and ends at 2014. They are available on an annual basis. The CAPM short-term beta[11] is a one-year estimate of beta that approximately involves regressing daily rates of return on the public utility common stock on a market index as shown footnote 10. The standard beta available from financial firm databases such as Value Line Investment Survey or CRSP is a 5-year beta based on regressing monthly or weekly common stock rates of return for the past 5 years on a market index. We find that the longer-term beta would be less sensitive to regime changes in risk such as decoupling. We restrict the sample of pre- and post-decoupling betas for each common stock so that the number of beta observations are the same before and after decoupling.

Since the number of data observations has different times series of ranges for each public utility common stock and decoupling occurred on different dates for most utilities, we have developed Table 1 to show each public utility common stock's data date range, that is, the dates and number of risk premium (rate of return minus risk-free rate) observations used to estimate the GCAPM and the total number of betas used for the pre- and post beta comparison. Table 1 also has the date of decoupling for each public utility.

5. Results and discussion

Table 2 presents the public utility common stocks in the study and the empirical results of the GCAPM estimates. The risk-premium-to-volatility slopes ("alpha") are shown along with the decoupling slope in the risk-premium and volatility equations for each electric, electric and gas combination, and water utility common stocks. The decoupling slope in the risk-premium equation will be negative (positive) if the risk premium should decline (rise) and decoupling creates a reduction (increase) in business risk. None of these slope estimates are statistically significant. The decoupling slope in the volatility equation should be negative (positive) if decoupling caused a reduction (increase) in the volatility of the profit of the utilities. Two of the slopes are negative and significant at $p = 0.10$, yet the magnitudes of the slopes are very small.

All of the alphas, except for one of the energy utilities are positive and significant, yet none in the water utility group are significant. These results indicate that the energy utility common stocks are not business cycle hedging assets and that their profits are synchronized with the business cycle. The results for the water group may indicate that they are business cycle hedging assets as none are statistically significant. The zero value for alpha implies that there is no relation between the business cycle as represented by expected changes in consumption and the return on water utility common stocks. Water utility profits are not correlated with the business cycle even in the absence of decoupling. Also, water use attrition is occurring across the US as households (water consumption per household is declining) due to the use of water-efficient appliances (such as low-flow faucets, showerheads and efficient toilets) and the change per capita water use habits to conserve water.

Table 3 presents the pre- and post-decoupling changes in the systematic risk as represented by the short-term CAPM beta for all of the public utility common stocks. The betas drop after the implementation of decoupling but none of the changes in beta are statistically significant using a t-statistic at a $p = 0.05$. Additionally, the standard errors of the betas (σ_{pre} and σ_{post}) show no consistent pattern of increasing or decreasing after decoupling.

Our results do not show any statistically significant impacts of decoupling on the cost of common equity and risk. Therefore, we find no evidence to conclude that decoupling affects investor perceived risk or the cost of common equity. While electric and gas public utility common stocks were not found to be business cycle hedges, we do find that water utility common stocks may be business cycle hedges.

Our results are based on the moderate amount of data available to date. Although we would obviously prefer more data than are available at this juncture, there is no time to wait for a larger volume of data. Regulators and utilities have been and are implementing policy now as if decoupling does reduce risk and the costs of capital without any

[11] The CRSP short-term beta is described by CRSP as "a statistical measurement of the relationship between two time series, and has been used to compare security data with benchmark data to measure risk in financial data analysis. CRSP provides annual betas computed using the methods developed by Scholes and Williams (Myron Scholes and Joseph Williams, "Estimating Betas from Nonsynchronous Data," *Journal of Financial Economics*, vol 5, 1977, 309–327). Beta is calculated each year as follows where.

$$\beta_i = \frac{\Sigma(lr_{i,t} * M3_t) - \left(\frac{1}{n_i}\right) * (\Sigma lr_{i,t}) * (\Sigma M3_t)}{\Sigma(lM_t * M3_t) - \left(\frac{1}{n_i}\right) * (\Sigma lM_t) * (\Sigma M3_t)}$$

Table 1
Data description for risk premiums and betas.

Electric, Elec. & Gas Comb. Utility	Effective Decoupling Date	Beginning of Measurement Period Returns Data	Total # of Months Return Data	Total Number of Pre- and Post- Annual Beta Observations
Consolidated Edison	10/2007	07/30/02	126	10
Pacific Gas & Electric	01/1983	01/31/53	720	60
Edison International	01/1983	01/31/53	720	60
CH Energy Group	07/2009	01/31/06	84	6
CMS Energy Corp.	05/2010	9/30/07	64	6
Hawaii Electric	12/2010	11/30/08	50	5
Portland General Electric	12/2010	11/30/08	50	6
Idaho Power	03/2007	05/30/01	140	12
Water Utility				
American States Water	1/2002	6/2002	153	12
California Water	1/2009	10/2001	162	12
Connecticut Water	7/2008	10/2002	150	10
Artesian Resources	11/2008	6/1996	226	12

Table 2
GCAPM estimation results.[a]

Electric, Elec. & Gas Comb. Utility	α_i	α_D	β_D
Consolidated Edison	1.460***	0.004	−0.000
Pacific Gas & Electric	1.781***	0.001	−0.001
Edison International	1.379***	0.003	0.000
CH Energy Group	2.094***	0.004	−0.000
CMS Energy Corp.	1.440***	0.011	−0.000
Hawaii Electric	1.607***	0.004	−0.000*
Portland General Electric	0.461	0.010	−0.000
Idaho Power	1.939***	0.003	−0.000
Water Utility	$\boldsymbol{\alpha_i}$	$\boldsymbol{\alpha_D}$	$\boldsymbol{\beta_D}$
American States Water	0.596	0.011	0.000
California Water	0.525	0.004	−0.000
Connecticut Water	−1.008	0.009	0.000
Artesian Resources	3.006	−0.004	−0.002*

[a] The GCAPM was estimated with the GARCH-M method. The estimated models are.

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \alpha_{i,D}D_{i,t} + \varepsilon_{i,t+1}$$

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \eta_{i,t+1},$$

And $R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma_{i,t+1}^2 + \varepsilon_{i,t+1}$

$$\sigma_{i,t+1}^2 = \beta_0 + \beta_1\sigma_{i,t}^2 + \beta_2\varepsilon_{i,t}^2 + \beta_{i,D}D_{i,t} + \eta_{i,t+1}.$$

Table 3
Changes in systematic risk from decoupling. [a]

	Mean β_{PRE}	Mean β_{POST}	σ (β_{PRE})	$\sigma(\beta_{POST})$	t-Statistic
Electric, Elec. & Gas Comb. Utility					
Consolidated Edison	0.608	0.427	0.172	0.064	−1.329
Pacific Gas & Electric	0.522	0.535	0.174	0.373	0.112
Edison International	0.588	0.582	0.199	0.294	−0.051
CH Energy Group	0.680	0.401	0.279	0.326	−0.759
CMS Energy Corp.	0.758	0.559	0.198	0.140	−0.815
Hawaii Electric	0.619	0.570	0.253	0.155	−0.171
Portland General Electric	0.637	0.658	0.069	0.052	−0.151
Idaho Power	0.905	0.728	0.251	0.125	−0.818
Mean	0.670	0.560			
Water Utility					
American States Water	0.975	0.623	0.535	0.279	−1.430
California Water	1.192	0.520	0.544	0.257	−2.735***
Connecticut Water	0.664	0.502	0.235	0.176	−1.232
Artesian Resources	0.075	0.146	0.100	0.161	0.909
Mean	0.434	0.475			

[a] Beta is the annual year-ending beta from the CRSP database. The data timeframe is different for each utility with an equal number of annual pre- and post-decoupling beta data observations for the specific stock in the CSRP database and ends in 2014. Each single beta was estimated with one year of daily rate of return data. See Table 1 and footnote 11. ***, **, * refers to statistical significance at 0.01, 0.05, and 0.10 respectively.

evidence that it does. This paper serves as an early warning signal, albeit with the limited evidence that is available.

6. Conclusion and policy implications

We conclude that decoupling has no statistically measurable impact on the cost of common equity based on our empirical analysis for electric, electric and gas, and water utility common stocks. Some researchers may view this result as a "non-result." This is an important finding as it is consistent with the empirical findings of Vilbert et al. (2016). It is also important for policy globally as decoupling is considered as a potential reducer to risk and the cost of common equity by regulators and public utilities in the US based on intuition, without any empirical evidence.

Moody's (2011) finds a reduction in business risk as measured by the change in the variability of gross profit after decoupling but did not estimate the impact on the cost of common equity. Moody's (2011) did find that electric utilities were somewhat reluctant to adopt decoupling as electric utility executives anticipated that growth in sales would return to the industry after the steep recession that ended with the business cycle trough in June 2009 {NBER (2018)}. Since the US business cycle expansion post-June 2009, electricity sales have remained almost flat, which may have caused the change in sentiment toward decoupling by electric utility executives. Growth in a utility's commodity sales above the level used to design regulated rates would increase the profit and rate of return on common equity. The US investor-owned electric utility industry also expected that the adoption of decoupling would cause state public utility regulators to reduce their allowed rate of return under the notion that it reduces risk. Moody's (2011) was written soon after the recession had ended, but the anticipated growth in sales has not materialized after more than ten years into the US business cycle expansion. A few years after the Moody's (2011) study, the EEI found in a more recent report a change in sentiment {EEI (2015)} that electric utilities favor decoupling and that it has become more widespread across the US.

We conclude that decoupling has no statistically significant impact on investor perceived risk and the cost of common equity. This does not mean necessarily that decoupling has no impact on the perceived risk and the cost of common equity of public utilities. We find that it cannot be isolated and estimated, given the many other factors affecting investor perceived risk. For many electric utilities, some current major risk drivers are flat or declining sales from customer-owned solar projects and energy efficiency resources; the requirement to buy back excess customer generated electric from renewable resources at full retail rates (net metering); increasing requirements in the proportion of a utility's sales that have to be generated from renewable energy, causing larger purchases of renewable energy credits (known as renewable portfolio standards that have been adopted by many states and across Europe); increasingly stringent environmental regulations on coal plants; and the impact of falling and low natural gas prices on the competitiveness of existing coal and nuclear plants.

For water utilities, we find their common stocks to be moderate business cycle hedges (no correlation with the business cycle rather than a strong negatively correlated hedge). Since water utility sales are declining on a per capita basis and unassociated with the business cycle, decoupling may provide financial protection if water revenues decline. To the extent that there is positive growth in the number of water utility customers that offsets the declining per capita consumption, total revenues and sales may not be falling. The impact of decoupling on water utility investment risk and cost of common equity was not able to be detected in this study. This is the first study on decoupling in the water utility industry and an area for future research.

Another explanation for the lack of detection of a change in risk or the cost of common equity from decoupling is that risk may be created with the implementation of decoupling and the net impact may not be clear as an increase or decrease in risk as Vilbert et. al. (2016) and Wharton and Vilbert (2015) concludes. They find that the implementation of decoupling is a new and alternative regulatory regime that may be a new source of regulatory risk for the utility. Finally, as discussed in detail in the Introduction above, volume risk, that is, the fundamental nature of the business and business risk, is not alleviated by changing the reward mechanism, and attempts to do so may increase risk and the cost of common equity. The point is that there are cogent theoretical and practical bases to expect that decoupling increases or decreases risk, so it is problematic to develop an *a priori* hypothesis to test a one-way directional impact of risk and return from decoupling.

Therefore, we do not recommend that public utility regulators in the US or elsewhere reduce or increase authorized common equity cost rates in the presence of decoupling mechanisms based on the assumption of changed or reduced risk. The impact is *de minimis* and not statistically significant amongst all of the other investor perceived risk factors affecting the market prices of public utility common stocks. While an alternative research approach may attempt to isolate the impacts of other individual risk factors on the cost of common equity and risk, making for a long regression equation, we cannot detect a statistically significant signal of decoupling on the cost of common equity or volatility. As a contrast, for example, the risk and cost of common equity impact of owning nuclear power generation assets (versus no nuclear assets) has a measureable impact on investors' returns, risk and cost of common equity without attempting to isolate the myriad of other risk variable impacts. Decoupling as a regulatory policy mechanism to encourage public utilities to provide resources and funding to their consumers to conserve electricity, natural gas, and water (therefore also wastewater flows) has no *measurable* impact on the investment risk and the cost of common equity (either up or down). As a policy prescription, public utility regulators should not adjust the allowed rate of return which affects the public utility's rates as a spillover impact of using decoupling to promote environmental policy.

Finally, the US may be further ahead in adopting rate mechanisms that address energy and water efficiency due to its long-term lag relative to Europe in the efficient use of energy and water and the recent "necessity-is-the-mother-of-invention" US driver of energy and water efficiency. European and regulators globally should proceed slowly in adopting decoupling and assuming that decoupling reduces risk as there is no empirical evidence to date that it does.

An extension of this research could evaluate risk premiums or discounts in bond yields as there are many more investor-owned utilities which have outstanding bonds relative to those that have their own publicly traded common stock due to consolidation in the utility industry in the US. For example, Exelon is the holding company of six utilities whose stocks were publicly traded on the New York Stock Exchange. They are Atlantic City Electric, Baltimore Gas and Electric, Commonwealth Edison, Delmarva Power and Light, Philadelphia Electric and Potomac Edison Power. Another future extension could focus on decoupling when some EU investor-owned utilities and regulators, inevitably, adopt decoupling should it prove to substantially encourage more conservation in the US. An investigation of hedging costs and savings, risk impacts, and effects on profits with and without decoupling may shed more light on the topic. There also needs more research on water/wastewater decoupling as this is the first study known to date on the topic involving cost of capital and risk. Lastly, a social welfare comparison, separating out consumer-surplus and shareholder-value creation and investigating the impacts on conservation from price and revenue caps is another extension of this paper for future research.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2019.04.006.where R_i is the conditional total return on the stock, R_f is the risk-free rate of return, $\sigma^2_{i,\ t+1}$ is the next period conditional volatility, D is the dummy variable that equals 1 when decoupling is in place, and α_D and β_D are the slopes on the conditional returns and volatility decoupling dummy variable that represent the impact of decoupling on those variables. Monthly returns data are from the CRSP database and includes all data available from the CRSP database and ends at 12/2014. The monthly risk-free rate of return is the Ibbotson income return on Long-Term US Treasuries. ***, **, * refers to statistical significance at p values of 0.01, 0.05 and 0.10 respectively.where R_i is the conditional total return on the stock, R_f is the risk-free rate of return, $\sigma_{2i,\ t+1}$ is the next period conditional volatility of the risk premium for asset *i*. $\varepsilon_{i,t}$ and $\eta_{i,t+1}$ are the error terms for the mean and volatility equations, D is the dummy variable that equals 1 when decoupling is in place for utility *i*, and α_D and β_D are the slopes on the conditional returns and volatility decoupling dummy variable that represent the impact of decoupling on those variables.

The parameter, α_i, is the risk-premium-to-volatility slope. It is specified from equation (1) as:

$$\alpha_{i,t} = -\frac{vol_t\,[M_{t+1}]}{E_t\,[M_{t+1}]}corr_t\,[M_{t+1},\ R_{i,t+1}]$$

It is positive for assets that are not business cycle hedges as $corr_t$ is negative. A rising (falling) M and rising (falling) expected marginal utility from falling (rising) consumption in a recession is associated with a fall (rise) in returns. The above empirical model specifies a 0 intercept in the risk premium equation as does the GCAPM. The estimation results support the 0 intercept specification (results available upon request).

β_i is the Beta for security i for the year being calculated, $r_{i,t}$ is the return of security i at day t,$lr_{i,t} = \ln(1+r_{i,t})$ is the natural log of the return of security i at time $t+1$ or the continuously compounded return, M_t is the value-weighted market return at time t, $lM_t = \ln(1+M_t)$ is the natural log of the value-weighted market return at time $t+1$ or the continuously compounded return.

$M3_t = lM_t\text{-}1 + lM_t + lM_{t+1}$ is the three-day moving window of the above market return, n_i is the number of non-missing returns for security i during the year, where the summations are over t and include all days on which security i traded, beginning with the first trading day of the year and ending with the last trading day of the year."

(http://www.crsp.com/products/documentation/index-definitions-calculations, accessed March 12, 2019.)

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BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2017-292-WS - ORDER NO. 2018-345

MAY 17, 2018

IN RE:	Application of Carolina Water Service, Inc. for Adjustment of Rates and Charges and Modification to Certain Terms and Conditions for the Provision of Water and Sewer Service	)))))	ORDER APPROVING RATES AND CHARGES

This matter is before the Public Service Commission of South Carolina ("Commission") on the Application of Carolina Water Service, Inc. ("CWS" or "Company") for approval of a new schedule of rates and charges and modifications to certain terms and conditions for the provision of water and sewer services for its customers in South Carolina. CWS filed its Application on November 10, 2017, pursuant to S.C. Code § 58-5-240 and S.C. Code Regs. §§ 103-503, 103-703, 103-512.4.A and 103-712.4.A.

In the Application, CWS requested an increase in revenues for combined operations of $4,511,414 consisting of a water revenue increase of $2,272,914 and a sewer revenue increase of $2,238,500. The revenue increase utilizes a return on equity (“ROE”) of 10.5% based on the rate of return on rate base methodology and a historical test year beginning September 1, 2016, and ending August 31, 2017.

CWS requested permission to modify its sewer service tariff to reduce the frequency with which customers must test their backflow devices from every year to every two years, and to authorize the Company to terminate service, after notice, to a customer who fails to demonstrate that his backflow device is working properly. App. p. 6, ¶ 20. CWS requested authorization to increase its Water Meter Installation Charge from $35 to $45 per year, to more accurately reflect the utility's cost of providing this service. App. p. 6, ¶ 21. The Company also requested approval of a provision in its tariff limiting the liability of the Company, its agents, and employees for interruption of service, whether caused by acts or omissions, to those remedies provided in the Commission's rules and regulations. App. p. 6, ¶ 22.

CWS last rate case before this Commission was in Docket No. 2015-199-WS. In that case, the Commission approved a settlement in which CWS received a combined revenue increase of $3,068,441 based on a $50,955,443 rate base; an operating margin of 11.95%, an ROE of 9.34%, and a return on rate base of 7.99%.

CWS' South Carolina operations are classified by the National Association of Regulatory Utility Commissioners ("NARUC") as a Class A water and wastewater utility according to water and sewer revenues reported on its Application for the test year ending August 31, 2017. The Commission's approved service area for CWS is in parts of sixteen counties.

I. PROCEDURAL BACKGROUND

The Commission's Clerk's Office instructed CWS to publish a prepared Notice of Filing, one time, in a newspaper of general circulation in the area affected by CWS' Application and to mail copies of the Notice of Filing to all customers affected by the proposed rates and charges and modifications. The Notice of Filing indicated the nature of the Application and advised all interested parties desiring to participate in the scheduled proceeding of the manner and time in which to file the appropriate pleadings. CWS filed affidavits demonstrating the Notice of Filing had been duly published and provided to all customers.

Petitions to Intervene were subsequently filed on behalf of the Forty Love Point Homeowners' Association ("Forty Love"), York County, and James S. Knowlton. The South Carolina Office of Regulatory Staff ("ORS"), a party of record pursuant to S.C. Code § 58-4-10(B), made on-site investigations of CWS' facilities, audited CWS' books and records, issued data requests, and gathered other detailed information concerning CWS' operations.

CWS was represented by Charles L.A. Terreni, and Scott Elliott. Laura P. Valtorta represented Forty Love. Michael K. Kendree represented York County, Mr. Knowlton appeared pro se. Jeffrey M. Nelson, and Florence P. Belser represented the ORS. On March 28, 2018 York County moved to withdraw from the proceedings without prejudice after CWS withdrew its request for approval of the Utility System Improvement Rate ("USIR"). York County's request was granted on the same day. Order No. 2018-38-H.

The Commission held public hearings in Lexington, York, and Greenville counties to allow CWS's customers to present their views regarding the Application. An evidentiary hearing was held April 3-4, 2018, at the Commission's offices in Columbia with the Honorable Swain E. Whitfield, presiding.

The Company presented the testimony of Michael R. Cartin, Operations and Regulatory Affairs Manager (direct, rebuttal and supplemental), Robert M. Hunter, Financial Planning and Analysis Manager (direct and rebuttal), and Bob Gilroy, Vice President of Operations (direct, rebuttal, and testimony responsive to customers who testified at public hearings). Mr. Cartin, testified about the Company's operations and various expenses and capital expenditures made by CWS. Mr. Hunter testified about the Company's finances and revenue requirement, and Mr. Gilroy testified about various aspects of the Company's operations and customer service. The Company also presented the testimony of Dylan W. D'Ascendis, CRRA, Director at ScottMadden, Inc., who testified to the Company's capital structure, cost of debt, and recommended ROE.

Forty Love presented the direct testimony of subdivision residents and customers Barbara King and Jay Dixon. They testified to problems experienced with the sewer system serving Forty Love Point. Mr. Knowlton presented his rebuttal testimony opposing the amount and frequency of the Company's rate increases.

ORS presented the testimony of Matthew Schellinger (direct and surrebuttal), Zachary Payne (direct and surrebuttal), and Douglas H. Carlisle, Jr., Ph.D. (direct and surrebuttal) as a panel. Dr. Carlisle testified to the Company's capital structure, cost of debt, and recommended ROE.

Dr. Carlisle's testimony included an analysis and recommendation for an allowed ROE. Mr. Payne testified about ORS's examination of the Application and CWS' books and records and the subsequent accounting and pro forma adjustments recommended by ORS. Mr. Schellinger's direct testimony focused on CWS' compliance with Commission rules and regulations, ORS' business office compliance review, inspections of CWS' water and wastewater systems, test year and proposed revenue, and performance bond requirements.

II. REVIEW OF THE EVIDENCE AND EVIDENTIARY CONCLUSIONS

A. Standards and Required Findings

In considering the Application, the Commission must ascertain and fix just and reasonable rates, standards, classifications, regulations, practices, and measurements of service to be furnished. The Commission must give due consideration to the Company's total revenue requirements and review the operating revenues and operating expenses of CWS to establish adequate and reasonable levels of revenues and expenses. The Commission will consider a fair rate of return for CWS based on the record and any increase must be just and reasonable and free of undue discrimination. CWS has also asked this Commission to approve revenues based on an authorized ROE established to allow CWS the opportunity to earn a fair return.

After evaluation of the positions of the parties, the Commission reaches the legal and factual conclusions discussed below, based on its review of the facts and evidence of record. The evidence supporting the Company's business and legal status is contained in the Application filed by CWS, testimony, and in prior Commission orders in the docket files of the Commission, of which the Commission takes judicial notice.

CWS has approximately 16,000 water customers and 14,000 sewer customers in Lexington, Richland, Sumter, Aiken, Saluda, Orangeburg, Beaufort, Georgetown, Abbeville, Union, Anderson, York, Cherokee, Greenville, Greenwood, and Williamsburg counties. App. Schd. F; R. p. 345 (Gilroy Dir. p. 2, ll. 21-24). As a public utility, its operations are subject to the jurisdiction of the Commission pursuant to S.C. Code §§ 58-5-10 et seq.

B. Test Year

A fundamental principle of the ratemaking process is the establishment of a historical test year as the basis for calculating a utility's return on rate base. To determine the utility's expenses and revenues, we must select a 'test year' for the measurement of the expenses and revenues. Heater of Seabrook v. PSC, 324 S.C. 56, 59 n.1 (1996). While the Commission considers a utility's proposed rate increase based upon occurrences within the test year, the Commission will also consider adjustments for any known and measurable out-of-test year changes in expenses, revenues, and investments, and will also consider adjustments for any unusual situations which occurred in the test year. When the test year figures are atypical, the Commission should adjust the test year data. See S. Bell Tel. & Tel. Co. v. Pub. Serv. Com, 270 S.C. 590, 603 (1978).

In its Application, CWS utilized a historic test year, the twelve months beginning September 1, 2016, and ending August 31, 2017, with adjustments for 2018 expectations. App. p.2, ¶ 5. ORS used the same historical test year. R. p. 729 (Payne Dir. p. 2, ll. 5-10). None of the other parties contested CWS' proposed test year. Based on the information available to the Commission, and that none of the parties objected to CWS' proposed test year, the Commission concludes that the test year beginning September 1, 2016, and ending August 31, 2017, is appropriate for this Application.

C. Rate of Return on Rate Base

The Company requested rate base and rate of return treatment for its Application. App. pp. 4-5, ¶ 16. No other party of record proposed an alternative method for determining just and reasonable rates and the testimony of ORS' witnesses Payne and Carlisle assumes that return on rate base will be the methodology employed.

The Commission has wide latitude in selecting a rate setting methodology. Heater of Seabrook, at 64. Even though S.C. Code § 58-5-240(H) requires the Commission to specify an operating margin in all water and sewer rate cases, the Commission is not precluded by that statute from employing the return on rate base approach to ratemaking. Id. Operating margin "is less appropriate for utilities that have large rate bases and need to earn a rate of return sufficient to obtain the necessary debt and equity capital that a large utility needs for sound operation." Id at 65. In the Company's last rate case, the Commission employed the return on rate base methodology. The Commission finds the return on rate base methodology is appropriate. The Company's rate base, according to its Application, is $54,853,170. App. Ex. B, Sch. C, p. 1.

The determination of return on rate base requires consideration of three components, namely: capital structure, cost of equity (or “ROE”) and the cost of debt. R. pp. 397-398 (D’ Ascendis Dir. pp. 4-5).

Mr. D’Ascendis and Dr. Carlisle agreed the capital structure and cost of debt of CWS's parent, Utilities, Inc. should be employed: it is 48.11% long-term debt and 51.89% common equity. R. pp. 395 (D’Ascendis Dir. p. 2, ll. 10-17); 649 (Carlisle Dir. p.4, ll. 21-

p.5, l. 3). No other party disagreed. The Commission finds this capital structure supported by the uncontroverted testimony of the parties.

Mr. D'Ascendis and Dr. Carlisle disagreed on CWS's cost of debt. Mr. D'Ascendis used an embedded debt rate of 6.60%. Dr. Carlisle lowered CWS's cost of debt rate from 6.60% to 6.58% due to what he described as "unfavorable terms" of the Company's long-term debt. R. p. 649 (Carlisle Dir., p. 4, l. 21 – p. 5, l. 9). Dr. Carlisle argued the Company imprudently refinanced its long-term debt when interest rates were high and agreed to terms which prevent it from refinancing now that interest rates are lower. Id. Mr. D' Ascendis countered that the Company's long-term debt financing, which was agreed to in 2006, was in line with bond yields for similarly situated companies at the time. R. p. 438 (D'Ascendis, Rebut. p. 3, ll. 1-14). However, the Commission has not been provided any evidence to support the ORS position. We find the appropriate long-term debt rate for CWS is 6.60%.

The rate of return on common equity, or ROE, is a key figure used in calculating a utility's overall rate of return. Porter v. PSC, 333 S.C. 12 (1998). A utility is entitled to the opportunity to earn a fair rate of return. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield Water Works Improvement Co. v. Public Service Comm'n, 262 U.S. 679 (1922),

Mr. D'Ascendis recommended that CWS' ROE should fall within a range of 10.45% to 10.95%. R. p. 397 (D'Ascendis Dir. p. 4, ll. 4-20 (Table 2)).

To determine the cost of equity, Mr. D'Ascendis used the Discounted Cash Flow ("DCF") Risk Premium Model ("RPM") and the Capital Asset Pricing Model ("CAP-M") and ("ECAP-M") model to similar risk companies, i.e. proxy groups, of regulated and non-regulated companies. R. pp. 396-397 (D'Ascendis Direct pp. 3-4).

The proxy groups were used by Mr. D'Ascendis because the Company's common stock is not publicly traded, and, therefore, CWS's market-based common equity cost rates cannot be determined directly. Id. He used a proxy group of eight water companies whose common stocks were actively traded for insight into a common equity cost rate applicable to CWS. R. p. 402 (D'Ascendis Direct, p.10). The utility proxy group was selected according to these criteria: 1) they are included in the Water Utility Group of Value Line's Standard Edition (October 13, 2017); 2) they have 70% or greater of 2016 total operating income and 70% or greater of 2016 total assets attributable to regulated water operations; 3) at the time of the preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e. one publicly traded utility merging with or acquiring another); 4) they have not cut or omitted their common dividends during the five years ending 2016 or through the time of the preparation of this testimony; 5) they have Value Line and Bloomberg adjusted betas; 6) they have a positive Value Line five-year dividends per share ("DPS") growth rate projection; and 7) they have Value Line, Reuters, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections. Id. The companies that met Mr. D'Ascendis' criteria were: American States Water Co., American Water Works Co., Inc., Aqua America, Inc., California Water Service Group, Connecticut Water Service, Inc., Middlesex Water Co., SJW Corp., and York Water Co. Id.

Mr. D'Ascendis also selected a proxy group of twenty-eight non-price regulated companies comparable in total risk to the proxy group of water companies. R. Ex. 8 (D'Ascendis Direct, Ex. 1, Schd. DWD-6). The criteria for non-price regulated proxy group were: 1) they must be covered by Value Line Investment Survey (Standard Edition); 2) they must be domestic, non-price regulated companies, i.e., non-utilities; 3) their beta coefficients must lie within plus or minus two standard deviations of the average unadjusted beta of the utility proxy group; and 4) the residual standard errors of the Value Line regressions, which gave rise to the unadjusted beta coefficients, must lie within plus or minus two standard deviations of the average residual standard error of the utility proxy group. R, p. 423 (D'Ascendis Direct, p. 30, ll. 15-23).

Mr. D'Ascendis' DCF analysis yields cost rates for the water company proxy group of 8.64%. The RPM analysis produced a common equity cost rate of 10.69% for the water company proxy group. The CAP-M cost rate is 10.51% for the water company proxy group. D'Ascendis averaged the mean, 10.43%, and median, 10.58%, equity costs of the water company proxy group, resulting in 10.51%. R. p. 424 (D'Ascendis Direct, p. 29, ll. 10-15). With the non-price regulated proxy group, the DCF yields 13.57%, the RPM, 11.91%, and the CAP-M/ECAP-M, 11.15%. R. p. 424 (D'Ascendis Direct, pp. 31, l. 12-32, l. 4). The average of the mean and median of the non-price regulated proxy group is 12.06%. R. p. 425 (D'Ascendis Direct, p. 32, ll. 7-14).

The approximate average of the results produced by any of Mr. D'Ascendis' models is 10.45%. R. p. 426 (D'Ascendis Direct, p. 33, ll. 5-9). He also recommended an upward adjustment of 0.50% ROE, due to CWS's small size. R. pp. 426 - 429 (D'Ascendis Direct,

p. 33, l. 11- 36, l. 20). His average ROE after the size adjustment is 10.95%. R. p. 429 (D’Ascendis Direct, p. 36, ll. 17-20). Mr. D’Ascendis recommended range of ROE was 10.45% to 10.95%. R. p. 397 (D’Ascendis Dir. p. 4, ll. 4-20 (Table 2)).

Dr. Carlisle employed the DCF model, the Comparable Earnings Model (“CEM”), and the CAP-M method to calculate his ROE range of 8.82% to 9.54%. R. p. 647 (Carlisle Direct, p. 2, ll. 12-15).

Dr. Carlisle also used a water company proxy group of ten water companies for his DCF and CAP-M analyses. R. p. 649 (Carlisle Direct, p. 4, ll. 15-20). Dr. Carlisle’s water company proxy group was identical to Mr. D’Ascendis’ water company proxy group except for the addition of Global Water Resources and Artesian Resources. Carlisle Rev. Exhibit DHC-4.

Dr. Carlisle’s DCF analysis yields cost rates for his water company proxy group of 8.82%. R. p. 654 (Carlisle Direct, p. 9, ll. 5-6). Dr. Carlisle did not perform the DCF analysis on non-price regulated proxy group as Mr. D’Ascendis did.

Dr. Carlisle’s CAP-M analysis compared the returns of the companies in his water company proxy group to a “risk free rate of return” (projected 30 yr. Treasury bond yield). R. p. 658 (Carlisle Direct, p. 13, ll. 17-23). Dr. Carlisle’s CAP-M analysis produced a range of 9.38% to 9.70%, which he averaged for a final CAP-M rate of 9.54%. R. p. 659 (Carlisle Direct, p. 14, ll. 12-13). Dr. Carlisle did not perform the CAP-M analysis on comparable non-price regulated stocks, as Mr. D’Ascendis did.

Dr. Carlisle’s CEM analysis, was applied to a group of non-price regulated stocks selected from Value Line with a comparable price volatility factor (“beta” or “ß”) to those in his water company proxy group. R. p. 655 (Carlisle Dir. p. 10, ll. 1-6). The CEM analysis produced a "retrospective" return on equity of 9.15%, and a "prospective" ROE of 8.63%. Dr. Carlisle averaged the two to arrive at a CEM ROE of 8.89%. R. p. 656 (Carlisle Dir. p. 11, ll. 3-7).

Finally, Dr. Carlisle averaged his DCF, CEM, and CAP-M rates to arrive at his recommended ROE of 9.08%.

Mr. D'Ascendis and Dr. Carlisle disagreed often. Mr. D'Ascendis argued that Dr. Carlisle should have relied on analysts' estimates of earnings per share rather than historical and projected measures of book value per share, dividends per share, and sales growth to predict growth in earnings per share when performing his DCF analysis. R. p. 438 (D'Ascendis, Rebut. p. 3, l. 15 – p. 7, l. 5). On the other hand, Dr. Carlisle took issue with Mr. D' Ascendis' reliance on analysts' projections of earnings per share ("EPS") as the sole factor in his DCF analysis. R. pp. 666–667 (Carlisle Surr. p. 5, l. 8 – p. 6, l. 12). Dr. Carlisle, instead, also considers dividends per share ("DPS"), book value per share ("BPS"), and revenue or sales. R. pp. 650-651 (Carlisle Dir., pp. 6-7). Mr. D'Ascendis pointed to common market references, such as Yahoo Finance and Bloomberg, which provide earnings per share projections, but not projections of dividends per share, book value per share or sales growth, as evidence the investment community relies on the former but not the latter. R. p. 458, l. 24 – p. 459, l. 13. Had he done so, Mr. D'Ascendis testified, Dr. Carlisle's analysis would have produced a higher ROE. R. p. 442 (D'Ascendis Rebut., p. 7, ll. 1-5). Dr. Carlisle disagreed, citing studies showing that analysts' estimates have been historically overly optimistic, and should not be the sole basis for the DCF analysis. R. pp. 664–666 (Carlisle, Surr. p. 3, l. 6 – p. 5, l. 4).

Mr. D'Ascendis also disagreed with Dr. Carlisle' CAP-M calculations. He argued that Dr. Carlisle used the wrong measures of market return, and that he should have used the arithmetic mean of monthly total return rates instead of a geometric mean (or compound growth rate). Mr. D'Ascendis contends using the arithmetic produces the best insight into future returns. R. pp. 443–445 (D' Ascendis Rebut. pp. 8-10). Dr. Carlisle responded that his market return measure better reflects the variety of companies in the market. Dr. Carlisle also defended his use of the geometric mean arguing that the arithmetic mean ignores the "compounding" effect of investing and can mislead investors by masking over the ups and downs of the market. R. p. 668 (Carlisle Surr. p. 7, l. 5 – p. 10, l. 26).

Mr. D'Ascendis criticized Dr. Carlisle for not performing an ECAP-M analysis, which he testified would have produced an equity cost rate of 10.03%. R. pp. 444–445 (D'Ascendis Rebut. p. 9, l. 8 – p. 10, l. 9). Mr. D'Ascendis also testified that Dr. Carlisle's selection of non-price regulated companies for his CEM analysis failed to reflect the total risk of his water company proxy group. Mr. D'Ascendis performed Dr. Carlisle's DCF and CAP-M analyses using a group that better reflected the risk of the water proxy group and found cost rates of 14.66% and 9.85% respectively. R. p. 448 (D'Ascendis Rebut. p. 13, ll. 14-24). Using the amended proxy group, Dr. Carlisle's range would change to 9.57% (DCF), 10.03% (CAP-M), and 12.26% (CEM) with an average of 10.62%. R. p. 449 (D'Ascendis Rebut. p. 14, ll. 4-10).

The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. . An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.

Table 1 below indicates the capital structure of the Company, the cost of debt, the cost of equity as approved in this Order, and the resulting rate of return on rate base:

Table 1: Summary of Overall Rate of Return

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.11%	6.60%	3.17%
Common Equity	51.89%	10.50%	5.45%
Total	100.00%		8.62%

D. Contested Rate Base Adjustments

The rate base proposed by CWS for combined operations was $54,853,170. App. Ex B., Sch. C. CWS disputed two of ORS's rate base adjustments: Adj. 32(c) in which ORS proposes to disallow $1,081,375 spent in connection with a liner of the equalization basin ("EQ Liner") at the Friarsgate wastewater treatment plant, and Adj. 32(d) in which ORS proposes to disallow $306,552 in engineering costs incurred at the Friarsgate Plant. R. p. 744 (Payne Direct, p. 17).

1. Friarsgate EQ Basin Removal and Site Remediation

The Company proposes to include $1,081,375 for engineering costs and remediation costs associated with the replacement of the Equalization Basin's ("EQ") liner at the Friarsgate WWTF. An EQ Liner is a heavy-mill plastic liner placed in an in-ground basin that holds water. R. p. 478, ll. 20-24. CWS hired an engineering firm, W.K. Dickson, after an upset occurred at its Friarsgate Wastewater Treatment Facility ("Friarsgate Plant"). W.K. Dickson assisted CWS in formulating and presenting a Corrective Action Plan required by a Consent Order with DHEC. R. p. 555, l. 16 – p. 557, l. 1. W.K. Dickson submitted engineering plans on an expedited basis for various changes and improvements made to the plant. R. p. 555, ll. 19-25. DHEC also required CWS to have a professional engineer who was a wastewater expert on site to supervise the plant's operations. R. p. 556, ll. 14-22. W.K Dickson also provided required monthly reports to DHEC. R. p. 556, l. 22 – p. 557, l. 1.

The Company was required by a DHEC Consent Order to: 1) remove the existing liner, 2) complete any environmental mitigation efforts concerning the soils under the existing liner, and 3) replace the EQ Liner. This effort included removing and properly disposing of any affected soils. Once the site was sufficiently mitigated, new soil was brought in, graded, and compacted to prepare the site for the installation of the new liner. Although the EQ plastic liner has yet to be installed, the Company removed the existing

EQ Liner and completed the environmental mitigation required by DHEC before the audit cutoff date of February 12, 2018. CWS acted expeditiously to comply with the DHEC mandate. CWS is not asking to recover the cost of the new liner. R. p. 505, ll. 8-14.

CWS witness Cartin testified that the DHEC Consent Order required CWS to remove the EQ Liner at the Friarsgate Plant, remediate the soil underneath the liner, and replace the liner. R. pp. 318-319 (Cartin Rebut. p. 3, l. 3 – p. 4, l. 2). CWS spent $1,081,375 to remove the EQ Liner and remediate the soil under the liner. Id. The Company had not installed the new liner yet but is in the process of doing so. Id. CWS contends that its compliance with DHEC's Consent Order was required for its continued operations and the public has benefitted from the removal of the old EQ Liner and the soil remediation, and therefore the costs should be included in rate base. Id.

The ORS proposes to disallow these costs because the EQ Liner has not yet been replaced. The ORS reasons that the project included both the engineering and remediation and the replacement of the EQ Liner. ORS's witness, Zachary Payne, testified that, since the new EQ Liner is still under construction, the whole project is not used and useful and should not be included in rate base. R. p. 754 (Payne Surr. p. 4, ll. 7-17).

The Commission finds the measures required by the DHEC Consent Order were in the public interest. Disallowing recovery of remediation costs acts to impair a utility's ability to address environmental concerns and conflicts with the policy of allowing recovery of necessary and prudently incurred costs. These known and measurable expenditures provided prompt regulatory and environmental compliance and immediate environmental and customer benefits. CWS has not requested recovery of the cost of the new EQ Liner, the part of the project that ORS challenges as not used and useful. The Commission finds the $1,081,375 cost of the removal of the existing EQ Liner and environmental remediation served the Company's customers and the public interest, and the Company is entitled to its recovery.

2. Friarsgate Engineering Costs

ORS proposed to disallow $306,552 in engineering costs paid to the W.K. Dickson firm for services at the Friarsgate Plant. R. p. 744 (Payne Direct, p. 17, l. 11 (Adj. 32(d)). CWS contends the costs are recoverable because W.K. Dickson was hired to comply with the terms of the Consent Order with DHEC. R. pp. 319-320 (Cartin Rebut. p. 4, l. 3 – p. 5, l. 4). Mr. Cartin testified that W.K. Dickson was hired to design an O&M Manual and take other measures to ensure compliance at the plant. Id. Mr. Gilroy testified that W.K. Dickson was continuously present at the plant following an upset that occurred in June 2016 whichled to a DHEC enforcement action. R. p. 353 (Gilroy Direct p. 10 ll. 1-7); R. p. 487, l. 12 – p. 488, l. 9. During that period, W.K. Dickson served as the principal point of contact with DHEC personnel and obtained permission for changes and improvements made to the facility. Id.

ORS took the position the W.K. Dickson costs should not be recoverable because they were incurred to comply with DHEC's Consent Order, which was caused by the Company's failure to adequately operate and maintain the Friarsgate Plant. R. p. 683, ll. 5-22. ORS's witness, Mr. Schellinger also testified the invoices for the work lacked sufficient detail to allow it to determine the work performed, and the work was required by Consent Orders which arose from the Company's violation of its NPDES permit. R.

pp.712-715 (Schellinger Surr. p. 5, l. 13 – p. 8, l. 20). If the costs were allowable, Mr. Schellinger testified that they should be booked as operations and maintenance expenses, not capital assets. CWS responded that costs incurred to ensure the Company's compliance with environmental regulations should be recoverable, and that treating them as capital expenditures is consistent with the practice adopted by the Company and the ORS in the settlement of the last rate case. R. pp. 319 - 320 (Cartin Rebut. p. 4, l. 3 – p. 5, l. 4). The Commission finds the engineering fees are recoverable as a capital expense prudently incurred to ensure necessary compliance with environmental regulations.

E. Expenses

CWS contested adjustments proposed by the ORS to the Company's O&M expenses: a reduction of $96,892 in sludge hauling expenses (Adj. 9(d)), and the disallowance of $998,606 in legal expenses incurred during litigation involving the I-20 wastewater treatment plant (Adj. 16).

1. Adjustment for Litigation Expenses

The Company proposes to amortize $998,606 in financial costs and litigation expenses associated with its I-20 sewer system over 66.67 years. R, pp. 316-317 (Cartin Rebut., p. 1, l. 12 – p. 2, l. 18). These costs were primarily incurred with five actions: 1) a lawsuit brought by the Congaree Riverkeeper in the U.S. District Court, 2) a condemnation action brought by the Town of Lexington, 3) a challenge to DHEC's denial of a permit for the I-20 Plant in the Administrative Law Court, 4) the Town of Lexington's challenge of DHEC's order that it interconnect with CWS brought in the Administrative Law Court, and 5) CWS's lawsuit against the EPA in the United States District Court. Schellinger Sur.

p. 3, ll. 1-11. The Company proposed to amortize these costs over 66.7 years, resulting in an expense of $14,979 per year. R. p. 300 (Cartin, Dir., p. 2, ll. 15-18).

ORS argued the legal expenses should not be allowed for two reasons. Mr. Schellinger testified that legal expenses incurred to defend the Congaree Riverkeeper's lawsuit should not be allowed because the District Court had ruled against CWS finding various violations of its NPDES permit and of effluent limitations since 2009. R. p. 692 (Schellinger Surr. p. 3, l. 11 – p. 4, l. 5). Mr. Schellinger viewed the company's lawsuit against the EPA and its litigation in the Administrative Law Court as related to the Riverkeeper proceeding, a position not disputed by CWS. Schellinger asserts that CWS should not be allowed to recover its legal costs because the actions arose from the Company's violations of environmental regulations. Id.

Schellinger testified the legal costs incurred in the condemnation action should not be recovered because CWS may be allowed to recover some costs if it prevailed. R. p. 730 (Schellinger Surr. p. 4, ll. 6-22). Schellinger also posited the actions before the Administrative Law Court could turn on the outcome of the condemnation action. R. p. 731 (Schellinger Surr. p. 5, ll. 1-12). He testified that since the outcome of the condemnation action was unknown and since if successful CWS may recover its litigation costs, the Commission should establish a regulatory asset in which to defer the litigation costs for future rate making treatment.

Mr. Cartin testified that CWS had no choice but to defend the Congaree Riverkeeper's lawsuit, and to prosecute its related actions. R. p. 490, l. 22 – p. 491, l. 7. He pointed out the Congaree Riverkeeper brought his suit to force an interconnection of the I-20 Plant to the Town of Lexington's sewer system, an action CWS was ready to take but the Town of Lexington would not allow. R. p. 489, ll. 8-20. It was not until 2016, after DHEC ordered the Town of Lexington to seek an interconnection with CWS, that Lexington brought its condemnation proceeding. R. p. 567, ll. 1-12. When the condemnation suit was brought, CWS readily allowed the town to take possession of the I-20 system and interconnect the plant, reserving its right to contest Lexington's valuation of the plant. Id.

The Commission finds that regulated utilities, like any business, will experience litigation costs associated with its business operations. CWS acted to limit exposure to liability and benefit the utility and its rate payers. The financial and litigation costs were prudently incurred. Recovery of these costs equates to $14,979 in annual amortization expense. As Mr. Cartin testified, CWS had no alternative but to defend the Congaree Riverkeeper's lawsuit and engage in the related litigation. Therefore, CWS will be allowed to recover $998,606 amortized over 66.7 years, at the rate of $14,979 per year.

2. Sludge Hauling Expenses

CWS incurred $284,233 in sludge hauling expenses at its Friarsgate Plant and at its Watergate wastewater treatment facility ("Watergate Plant") during the test year. R. p. 753 (Payne Surr. p. 3). ORS proposed to remove $96,892 in sludge hauling costs. ORS proposes an adjustment to allow recovery of a three-year average of annual sludge hauling costs at the two facilities.

ORS witness Payne testified that the ORS reviewed the sludge costs in the test year and the costs in the previous two years, concluding that the sludge hauling costs in the test year were atypical. R. pp. 751-752 (Payne Surr. p. 2, l. 19 – p. 3, l. 12). The ORS proposes to average the annual sludge expense for the three years reviewed and proposed an adjustment of $96,892, normalizing this operating expense. Id.

CWS witness Gilroy testified the increase of sludge hauling expense during the test year was caused by additional sludge removal requirements at the Friarsgate WWTF which produces large amounts of sludge that must be disposed of in a timely manner. R. pp. 358-360. The amount of sludge produced depends on many factors within the process of the waste water treatment. Id. The active sludge inventory within the process must be kept at a certain concentration for the biological process to be effective and result in a clear compliant effluent. Id. Excess sludge inventory must be removed frequently to keep sludge from building up to unacceptable levels which could cause problems with effluent quality. Id.

Mr. Gilroy testified that because the Friarsgate WWTF has been on a Consent Order, these sludge inventories are also monitored by DHEC, which recommends that the inventory to be kept at a constant rate. R. p. 365 (Gilroy Rebut. p. 3, ll. 3-12)). Ordinarily, the liquid sludge is poured into filtrate boxes that drain off the water leaving a very dry cake behind, which is then hauled and disposed of at the Northeast Sanitary Landfill. Id. When the sludge production exceeds the capacity of the filtrate boxes, CWS utilizes contractor liquid tanker trucks to haul the sludge to the City of Cayce's disposal site. Id. Disposing of the sludge in the cake form is more cost-effective than hauling truckloads of liquid sludge. Id. Although more expensive, sometimes the filtrate boxes are full, and tankers must be utilized. Id.

The Commission finds that the sludge hauling costs in the test year are recoverable as known and measurable, prudently incurred costs. The ORS does not dispute the sludge costs in the test year. It simply speculates that the costs will not recur in a similar amount. Speculation is not sufficient. Moreover, the testimony indicates that the sludge costs have increased because of the DHEC Consent Order, and were prudently incurred. The Commission denies the ORS adjustment to reduce the sludge hauling expenses.

3. Effects of the Income Tax and Jobs Act

a) Excess Accumulated Deferred Income Taxes

The Company filed its Application before Congress enacted the Tax Cuts and Jobs Act of 2017 ("TCJA"), which took effect on January 1, 2018. P.L. No: 115-97. The TCJA changed the tax laws affecting the Company. Mr. Hunter testified the TCJA reduced the corporate income tax rate from 35% to 21%, causing the Company to reduce its requested revenue requirement by approximately $877,000. R. p. 255, ll. 16-22. This Commission held in Order No. 2018-308 that, beginning January 1, 2018, regulatory accounting treatment is required for all regulated utilities for any impacts of the new law, including current and deferred tax impacts. We also held that the utilities should track and defer the effects resulting from the Tax Act in a regulatory liability account, and further, for water/wastewater utilities with operating revenues that are equal or greater than $250,000, the issue will be addressed at the next rate case or other proceeding. The provisions of Order No. 2018-308 apply to the present case, as well as to other utilities indicated in Order No. 2018-308.

F. Rate Case Expenses

CWS proposed to include rate case expenses incurred in this rate case through the date of the hearing, and ORS agreed to this proposal, subject to its review of the requested additional amount and examination of supporting documentation. R p. 754 (Payne Surreb., p. 4, ll. 5-7). ORS received and reviewed documentation supporting rate case expenses of $88,500 and informed the Commission at the hearing that the ORS agrees with them. After the hearing, CWS presented documentation supporting additional rate case expenses of $64,560. Because the additional rate case expenses are known and measurable, the Commission will allow them to be included in the total rate case expense and amortized over three years. We find the Company is entitled to $153,060 in total rate case expenses, including those expenses submitted to ORS post-hearing. This amount amortized over three years less the Company's per book amount yields a post-hearing adjustment of $21,520.

G. Other Adjustments

The remaining ORS adjustments are accepted by this Commission without discussion. They either were not disputed by the parties or were caused by carrying out the effects of the adjustments adopted above.

H. Deferred Accounts

By Order No. 2015-876 in Docket No. 2015-199-WS, the Commission approved two regulatory deferred accounts authorizing CWS 1) to record and monitor all rate increases from third-party providers for water supply and sewer treatment; and 2) to recover non-revenue water expenses. The Commission authorized CWS to seek recovery of the balance of these deferred accounts, subject to audit by ORS and approval by the Commission in a subsequent rate case. In this Application CWS is seeking recovery of the balance in the regulatory deferral account associated with increases in purchased water from bulk water providers. (Application, para. 17) Mr. Hunter testified that the purchase water deferred account had a balance of $669,808 as of March 8, 2018 and explained CWS sought recovery of this balance in this docket R. p. 278 (Hunter Rebut. p. 3 ll. 7–17). At the hearing, Mr. Payne testified that the ORS had reviewed the supporting documentation of the purchase water deferred account and that the ORS agreed with CWS' request to recover the balance of $669,808. R. p. 752 (Payne Surreb., p. 2, ll.8-18). The Commission finds it reasonable for CWS to recover the purchased water deferred account balance of $669,808.

Because the non-revenue water deferral account has a balance of zero, the ORS recommended this account be closed. R. p. 701 (Schellinger Dir., p. 11, l. 18 – p. 12, l. 8). The Company did not dispute this recommendation. The Commission finds it reasonable that the non-revenue water account be closed.

I. Performance Bond

CWS currently provides the maximum amount required for its performance bond in the amount of $350,000 for water and $350,000 for sewer operations. Using the criteria set forth in S.C. Code Regs. §§ 103-512.3.1 and 103-712.3.1, ORS recommended that CWS be required to continue the current performance bond amounts. R. p. 701 (Schellinger Dir. p. 12, ll. 9-15). CWS agreed to the performance bond amounts. The Commission requires that CWS maintain its performance bond in $350,000 for water and $350,000 for sewer operations.

J. Changes to Rates, Charges and Term of Service

1. Irrigation Only Meters

Mr. Cartin testified that after hearing concerns expressed by customers with irrigation only meters, the Company had determined to eliminate the base facilities charge for irrigation only meters for residential customers who are no longer receiving an economic benefit from having an irrigation meter. The impact on revenues will be $37,946 annually. The Company is not seeking recovery of this lost revenue here. R. p. 320 (Cartin Reb., p. 5, ll. 5-20).

The ORS has no objection to eliminating the base facilities charge on customers with irrigation only meters.

The Commission finds that eliminating the base facilities charge for customers with irrigation only meters is just and reasonable and in the public interest.

2. Backflow Testing.

CWS proposed to change the terms and conditions of its tariff to permit its customers to test their backflow devices every two years. The ORS proposed to limit the testing requirement to every two years for those residential customers with irrigation cross connections. R. pp. 699 - 700 (Schellinger Dir., p. 10, l. 18 – p. 11, l. 6). CWS concurred with the ORS recommendation with the additional provision that if the sewer system utilizes chemical injection, annual testing will be required. R. p. 363 (Gilroy Rebut., p. 1, ll. 1-7).

The Commission finds that permitting CWS' residential irrigation customers to test backflow preventers every two years is reasonable, provided that if the sewer system utilizes chemical injection, annual testing will be required

3. Water Meter Installation Charge

CWS requests authority to increase its Water Meter Installation Charge from$35.00 to $45.00 to more closely reflect the utility's costs. (Application at ¶ 20) The ORS has reviewed the cost justification for this increase and agrees the increase is reasonable. R. p. 699 (Schellinger Dir., p. 10, ll.14 – 17). The $45.00 charge is reasonable and CWS is authorized to increase its Water Meter Installation Charge to $45.00.

4. Limitation of Liability

CWS seeks authority to limit the liability of the Company, its agents and employees for damages arising out of interruption of service or the failure to furnish service, whether caused by acts or omission, to those remedies provided in the Commission's rules and regulations governing water and wastewater utilities. (Application at ¶ 22). Mr. Cartin points out that the Commission has promulgated regulations for quality of service and interruption of service. Limiting customer remedies to those provided in the regulations will eliminate the prospect of unnecessary litigation and result in cost savings which will benefit customers. R. pp. 310-311 (Cartin Dir., p. 12, l. 14 – p. 13 1, l. 2). The ORS does not oppose the Company's proposed changes to tariff language regarding liability for interruption of service. Interruption of service is regulated by the Commission in S.C, Code Ann. Regs. 103-771 and 103-551. R. p. 670 (Schellinger Dir., p. 11, ll. 7–12) The proposed limitation of liability to those protections found in S.C. Code Reg. 103-771 and 103-551 is reasonable and is approved.

K. Authorized Revenues

CWS requested in its Application to increase revenues for combined operations by $4,511,414, comprising a water revenue increase of $2,272,914 and a sewer revenue increase of $2,238,500, based on the rate of return on rate base methodology utilizing an ROE of 10.5% and an historical test year ending August 31, 2017. The revenue and expense adjustments to the requested increase in revenue set out herein at the approved ROE of 10.50% produce additional operating revenue of $2,936,437 consisting of a water revenue increase of $1,286,127 and a sewer revenue increase of $1,650,310.

L. Rate Design

Exhibit "A" to the Application contains the Company's Schedule of Proposed Water Charges. The proposed water rate structure for Territory 1 and Territory 2 will remain the same as approved in Order No. 2015-876. In Territory 1 and Territory 2 there will remain separate charges for Water Supply Customers (where water is supplied by wells owned and operated by CWS) and Water Distribution Customers (where water is purchased from a governmental body or agency or other entity for distribution and resale by CWS). R. p. 264 (Hunter Dir. p. 5, ll. 18–25).

Exhibit "A" to the Application contains the Company's Schedule of Proposed Sewer Charges. Under the existing tariff, the flat rate charge for Sewer Collection & Treatment Only Customers and the flat rate charge for Sewer Collection Only Customers are two different rates. CWS proposes to combine Sewer Collection & Treatment Only

Customers and Sewer Collection Only Customers into one single rate per unit. Separate rates will remain on the tariff for Mobile Homes, and The Village Sewer Collection Customers. R. p. 265 (Hunter Dir., p.6, ll. 16–23).

Rate design is a matter of discretion for the Commission. In establishing rates, it is incumbent upon us to fix rates which "distribute fairly the revenue requirements [of the utility]." See Seabrook Island Property Owners Association v. S.C. Public Service Comm'n, 303 S.C. 493, 499 (1991). Our determination of "fairness" with respect to the distribution of the Company's revenue requirement is subject to the requirement that it be based upon some objective and measurable framework. See Utilities Services of South Carolina, Inc., v. South Carolina Office of Regulatory Staff, 392 S.C. 96, 113-114 (2011).

CWS has combined certain of its sewer rates in this docket moving closer to uniform rates. The water rate design was approved by Order No. 2015-876. No party contests the proposed rate design and it is approved by the Commission.

M. Forty Love Point

The Forty Love Point Homeowners Association intervened questioning sewer service in the neighborhood. Barbara King and Jay Dixon, residents of the Forty Love subdivision, testified that they experienced sewer backups in their homes and chronicled the efforts of CWS to address their concerns. Representatives of CWS and its engineers, DHEC and ORS have met with the witnesses. CWS provides collection only services to Forty Love and Richland County treats the sewage. The witnesses testified that Richland County and CWS should coordinate any remedy for the customer concerns. The witnesses believe their sewer system is outdated and inadequate. The witnesses also contest the proposed rate increase. R. pp. 608–610 (Dixon Dir. p. 1, l. 1 – p. 4, l. 76); R. pp. 603 – 605 (King Dir., p. 1, l. 1 – p. 3, l. 59).

CWS witness Gilroy testified that the Forty Love sewer system is a LETTS design installed by the developer. LETTS systems are modified septic tanks in which solid waste accumulates in a holding tank with the gray water draining to a common sewer main for transport to the Richland County Utilities treatment plant. CWS has been working with the Kings and Dixons to determine why their LETTS tanks fail to drain during prolonged rain events. CWS believes the elevation and distance between their finished basements and the sewer main outside provides for no leeway when the sewer main backs up slightly. CWS has a contractor working to install a pump tank that will both pump their water into the main and provide the separation needed to eliminate backups of their homes. R. pp. 363–364 (Gilroy Rebut., p. 1, l. 8 – p. 2, l. 10).

CWS is also retaining a professional engineering firm to inspect the system and help solve the sewerage backup problems experienced by these customers. While it is working towards a permanent solution, CWS will continue to alleviate the problem by dispatching pump trucks to the neighborhood when heavy rains are anticipated. CWS is also inspecting each LETTS tank and will reseal them as necessary. Reduced water from the tanks should ease the stress placed on thesystem. Id.

CWS will continue to communicate the engineering assessment with the outside contractor with Forty Love. CWS and Forty Love have agreed to report their findings to the Commission and ORS in six months – by September 30, 2018. Id. The Commission finds that the agreement between CWS and Forty Love is reasonable.

CWS and the HOA have agreed to the following plan of action which, at their request, the Commission incorporates in its Order:

> CWS acknowledges that some of its customers in the Forty Love Point neighborhood have experienced problems with sewerage backups. CWS has taken, and will continue to take, measures to address these customers' concerns. CWS and the HOA agree to cooperatively investigate the source and extent of sewerage problems experienced by customers in the Forty Love Point neighborhood and formulate a plan to address them. The company is retaining an engineering firm to perform an assessment of the Forty Love Point system, and CWS will continue to work with DHEC and Richland County to determine whether issues with the latter's system may be affecting Forty Love Point. CWS and the HOA will report their findings to the PSC and the ORS in six months.

N. Dancing Dolphin, LLC

The Commission requested that the ORS investigate the allegations made by CWS' customer the Dancing Dolphin, LLC. The ORS recommends that CWS complete an inflow and infiltration study and a cost benefits analysis for the sewer system serving the properties owned by the Dancing Dolphin. R. pp. 705– 706 (Schellinger Dir., p. 16, l. 20 - -p. 17, l. 3) CWS will conduct an inflow and infiltration study and provide a report to the Commission within one year of the date of the Order. R. pp. 317–318 (Cartin Rebut., p. 2, 19 - p. 3, l. 2). In addition, CWS has credited the Dancing Dolphin, LLC with one month's bill to address the customer's concerns. R. p. 310 (Cartin Dir. p. 12, ll. 12–13). The Commission finds CWS conduct to be prudent and reasonable.

O. Customer Communications

The record reflects that CWS is working to give its customers a better understanding of the pressures and costs of operating its water and sewer systems. The Company has hired a communications coordinator to direct its customer outreach activities. R. pp. 251-253. Since December of 2017, CWS scheduled meetings with its customers in York County on December 4, 2017, and February 27, 2018; Lexington County on December 5, 2017; Anderson County on December 6, 2017; Richland County on February 21, 2018, and Greenville County on March 1, 2018. At those meetings, CWS gave customers the opportunity to meet with its management and field personnel to learn more about its operations and cost of service. R. p. 371 (Gilroy Resp., p.1, ll. 6–16).

This Commission would observe that, in prior years, the Company's customer service was perceived by some as being below standard. However, the Company's testimony in this case shows that it is committed to improvement in a proactive fashion. Relatively few customers appeared to complain about quality of service, as compared to the last several rate cases. We hold that the Company should routinely be responsive on quality of service issues, and that CWS should set the standard for quality and customer service.

However, in order to ensure that the Company is being responsive to quality of service issues, and to its customers, CWS shall prepare a report and submit it to the Commission and to ORS no less than semiannually, and the document should have headings for "Customer Complaint," "Company Response," "Customer Reaction to Company," and explain the Company reaction to Customer Complaints during the period addressed, along with any explanations regarding quality of service. The Company shall also submit a separate report no less than semiannually reporting on all capital improvements made during the period to enhance customer service and to explain the cost of such capital improvements.

III. FINDINGS OF FACT

1) CWS is a water and sewer utility providing water and sewer service in its assigned service area in South Carolina. The Commission is vested with authority to regulate rates of every public utility in this state and to ascertain and fix just and reasonable rates for service. S.C. §58-5-210, et. seq. CWS's operations in South Carolina are subject to the jurisdiction of the Commission.

2) CWS requested in its Application to increase revenues for combined operations by $4,511,414 comprising a water revenue increase of $2,272,914 and a sewer revenue increase of $2,238,500, based on the rate of return on rate base methodology utilizing an ROE of 10.5% and a historical test year ending August 31, 2017.

3) The test year period for this proceeding, selected by the Company, is September 1, 2016 through August 31, 2017.

4) The Commission will use the return on rate base methodology in determining and fixing just and reasonable rates.

5) The return on rate base methodology requires three components: capital structure, cost of debt, and cost of equity (or ROE).

6) CWS's rate base is $55,524,956 after the adjustments adopted by the Commission.

7) The Commission adopts and approves of a capital structure of 48.11% long-term debt and 51.89% equity; a cost of debt rate of 6.60%; and an ROE of 10.50%.

8) The approved capital structure, cost of debt rate, and ROE produce additional operating revenue of $2,936,437 consisting of a water revenue increase of $1,286,127 and a sewer revenue increase of $1,650,310.

9) The approved revenues and expenses establish a fair and reasonable operating margin of 13.23%, and a return on rate base of 8.62%.

10) The schedule of rates and terms and conditions attached to this Order as Exhibit A (Order Exhibit 1) are just and reasonable and designed to achieve the Company's new revenue requirement.

IV. CONCLUSIONS OF LAW

Based upon the discussion, findings of fact and the record of the instant proceeding, the Commission makes these Conclusions of Law:

1) CWS is a public utility as defined in S.C. Code § 58-5-10(3) and is subject to the jurisdiction of this Commission.

2) The appropriate test year on which to set rates for CWS is the twelve-month period beginning September 1, 2016 and ending August 31, 2017.

3) Based on the information provided by the parties, the Commission concludes the rate setting methodology to use as a guide in determining the lawfulness of CWS's proposed rates and for fixing just and reasonable rates is return on rate base.

4) For CWS to have the opportunity to earn the 10.5% ROE, found fair and reasonable herein, CWS must be allowed additional revenues of $2,936,437.

5) The schedule of rates and terms and conditions in the attached Exhibit A are approved for use by CWS and are just and reasonable without undue discrimination and are also designed to meet the revenue requirements of CWS.

6) Pursuant to S.C. Code § 58-5-720 and 10 S.C. Code Regs. §§ 103-512.3 and 103-712.3, CWS will post a performance bond of $350,000 for water and $350,000 for sewer operations.

V. ORDERING PROVISIONS

IT IS THEREFORE ORDERED THAT:

I. The rates, fees, and charges in Order Exhibit 1 are both fair and reasonable and will allow CWS to continue to provide its customers with adequate water and wastewater services.

II. The Company is to provide thirty (30) days' notice of the increase to customers of its water and wastewater services prior to the rates and schedules being put into effect for service rendered. The schedules will be deemed filed with the Commission under S.C. Code § 58-5-240.

III. An ROE of 10.5%, return on rate base of 8.62% and operating margin of 13.23% based on the new rates, fees, and charges, is approved for CWS.

IV. The Company will continue to maintain current performance bonds in the amounts of $350,000 for water operations and $350,000 for wastewater operations pursuant to S.C. Code § 58-5-720.

V. The Company shall provide the written reports on quality of service and capital improvements no less than semiannually as described above.

VI. This Order will remain in full force and effect until further order of the Commission.

BY ORDER OF THE COMMISSION:

Swain E. Whitfield

Swain E. Whitfield, Chairman

ATTEST:

Comer H Randall

Comer H. Randall, Vice Chairman

EXHIBIT A

Tariff

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

WATER

Service Territory 1

Monthly Charges - Water Supply Customers Only

Where water is supplied by wells owned and operated by the Utility, the following rates apply:

	Current	Proposed
Residential		
Base Facilities Charge per single-family house, condominium, mobile home, or apartment unit	$14.64 per unit	$14.43 per unit
Residential Commodity Charge	$5.69 per 1,000 gal. or 134 cft.	$5.61 per 1,000 gal. or 134 cft.
Commercial		
Base Facilities Charge by meter size		
5/8" meter *	$ 14.64 per unit	$ 14.43 per unit
3/4" meter	$ 14.64 per unit	$ 14.43 per unit
1" meter	$ 38.10 per unit	$ 37.54 per unit
1.5" meter	$ 76.21 per unit	$ 75.10 per unit
2" meter	$ 121.93 per unit	$ 120.15 per unit
3" meter	$ 228.63 per unit	$ 225.29 per unit
4" meter	$ 381.16 per unit	$ 375.59 per unit
8" meter	$1,171.21 per unit	$1,154.08 per unit
Commercial Commodity Charge	$5.69 per 1,000 gal or 134 cft.	$5.61 per 1,000 gal. or 134 cft.

Monthly Charges - Water Distribution Customers Only

Where water is purchased from a governmental body or agency or other entity for distribution and resale by the Utility, the following rates apply:

	Current	Proposed
Residential		
Base Facilities Charge per single-family house, condominium, mobile home, or apartment unit	$14.64 per unit	$14.43 per unit
Residential Commodity Charge	$6.67 per 1,000 gal. or 134 cft.	$7.57 per 1,000 gal. or 134 cft.

Corrected

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

	Current	Proposed
Commercial		
Base Facilities Charge		
by meter size		
5/8" meter *	$ 14.64 per unit	$ 14.43 per unit
3/4" meter	$ 14.64 per unit	$ 14.43 per unit
1" meter	$ 38.10 per unit	$ 37.54 per unit
1.5" meter	$ 76.21 per unit	$ 75.10 per unit
2" meter	$ 121.93 per unit	$ 120.15 per unit
3" meter	$ 228.63 per unit	$ 225.29 per unit
4" meter	$ 381.16 per unit	$ 375.59 per unit
8" meter	$1,171.21 per unit	$1,154.08 per unit
Commercial Commodity Charge	$6.67 per 1,000 gal. or 134 cft.	$7.57 per 1,000 gal. or 134 cft/

***A "Fire Line" customer will be billed a monthly base facilities charge of a 5/8" meter or at the rate of any other meter size used as a detector.**

Corrected

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

Service Territory 2

Monthly Charges - Water Supply Customers

Where water is supplied by wells owned and operated by the Utility, the following rates apply:

	Current	Proposed
Residential		
Base Facilities Charge per single-family house, condominium, mobile home or apartment unit:	$24.72 per unit	$28.62 per unit
Residential Commodity Charge	$ 8.88 per 1,000 gal. or 134 cft.	$10.28 per 1,000 gal. or 134 cft.
Commercial		
Base Facilities Charge by meter size		
5/8" meter*	$ 24.72 per unit	$ 28.62 per unit
1" meter	$ 68.81 per unit	$ 79.65 per unit
1.5" meter	$ 126.45 per unit	$146.38 per unit
3" meter	$ 431.52 per unit	$499.53 per unit
Commercial Commodity Charge	$ 8.88 per 1,000 gal. or 134 cft.	$10.28 per 1,000 gal. or 134 cft.

Monthly Charges - Water Distribution Customers Only

Where water is purchased from a governmental body or agency or other entity for distribution and resale by the Utility, the following rates apply:

	Current	Proposed
Residential		
Base Facilities Charge per single-family house, condominium, mobile home or apartment unit:	$ 24.72 per unit	$ 28.62 per unit
Residential Commodity Charge	$ 9.41 per 1,000 gal. or 134 cft.	$ 11.86 per 1,000 gal. or 134 cft.
Commercial		
Base Facilities Charge by meter size:		
5/8" meter*	$ 24.72 per unit	$ 28.62 per unit
1" meter	$ 68.81 per unit	$ 79.65 per unit
1.5" meter	$ 126.45 per unit	$146.38 per unit
3" meter	$ 431.52 per unit	$499.53 per unit
Commercial Commodity Charge	$ 9.41 per 1,000 gal.	$ 11.86 per 1,000 gal.

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

or 134 cft.	or 134 cft.

***A "Fire Line" customer will be billed a monthly base facilities charge of a 5/8" meter or at the rate of any other meter size used as a detector.**

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

WATER SERVICE
TERMS AND CONDITIONS
AND
NON-RECURRING CHARGES

1. **Terms and Conditions**

A. Where the Utility is required by regulatory authority with jurisdiction over the Utility to interconnect to the water supply system of a government body or agency or other entity and tap/connection/impact fees are imposed by that entity, such tap/connection/impact fees will also be charged to the Utility's affected customers on a pro rata basis, without markup.

B. Commercial customers are those not included in the residential category above and include, but are not limited to, hotels, stores, restaurants, offices, industry, etc.

C. The Utility will, for the convenience of the owner, bill a tenant in a multi-unit building, consisting of four or more residential units (or in such other circumstances as the law may allow from time to time), which is served by a master water meter or a single water connection. However, in such cases all arrearages must be satisfied before service will be provided to a new tenant or before interrupted service will be restored. Failure of an owner to pay for services rendered to a tenant in these circumstances may result in service interruptions.

D. When, because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit separately, service will be provided through a single meter, and consumption of all units will be averaged; a bill will be calculated based on that average and the result multiplied by the number of units served by a single meter.

E. Billing Cycle
Recurring charges will be billed monthly in arrears. Nonrecurring charges will be billed and collected in advance of service being provided.

F. Extension of Utility Service Lines and Mains
The Utility shall have no obligation at its expense to extend its utility service lines or mains in order to permit any customer to connect to its water system. However, anyone or entity which is willing to pay all costs associated with extending an appropriately sized and constructed main or utility service line from his/her/its premises to any appropriate connection point, and pay the appropriate fees and charges as set forth in this rate schedule, and comply with the guidelines and standards hereof, shall not be denied service unless water supply is unavailable or unless the South Carolina Department of Health and Environmental Control or other government entity has for any reason restricted the Utility from adding additional customers to the serving water system. In no event will the Utility be required to construct additional water supply capacity to serve any customer or entity without an agreement acceptable to the Utility first having been reached for the payment of all costs associated with adding water supply capacity to the affected water system.

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

G. Cross-Connection Inspection
Any customer installing, permitting to be installed, or maintain any cross connection between the Utilities water system and any other non-public water system, sewer, or a line from any container of liquids or other substances, must install an approved back-flow prevention device in accordance with 24A S.C. Code Ann. Regs. R.61-58.7.F.2, as may be amended for time to time. Such a customer shall have such cross connection inspected by a licensed certified tester and provide to Utility a copy of written inspection report indicating the back-flow device is functioning properly and testing results submitted by the tester in accordance with 24A S.C. Code Ann. Regs. R.61-58.7.F.2, as may be amended from time to time. Said report and results must be provided by the customer to the Utility no later June 30th of each year for required residential and commercial customers, provided that said report and results for residential irrigation customers shall be provided by the customer to the Utility no later than June 30th of every other year (unless the sewer system utilizes chemical injection for which annual testing will be required). Should a customer subject to these requirements fail to timely provide such report and results, Utility may arrange for inspection and testing by a licensed certified tester and add the charges incurred by the Utility in that regard to the customer's next bill. If after inspection and testing by the Utility's certified tester, the back-flow device fails to function properly, the customer will be notified and given a 30 day period in which to have the back-flow device repaired or replaced with a subsequent follow-up inspection by a licensed certified tester indicating the back-flow device is functioning properly. Failure to submit a report indicating the back-flow device is functioning properly will result in discontinuation of water service to said customer until such time as a passing inspection report is received by Utility.

H. A Single Family Equivalent (SFE) shall be determined by using the South Carolina Department of Health and Environmental Control Guidelines for Unit Contributory Loadings for Domestic Wastewater Treatment Facilities -- 6 S.C. Code Ann. Regs. 61-67 Appendix A, as may be amended from time to time. Where applicable, such guidelines shall be used for determination of the appropriate monthly service and tap fee. The Company shall have the right to request and receive water usage records from the water provider to its customers. In addition, the Company shall have the right to conduct an inspection of the customer's premises. If it is determined that actual flows or loadings are greater than the design flows or loadings, then the Company shall recalculate the customer's equivalency rating based on actual flows or loadings and thereafter bill for its services in accordance with such recalculated loadings.

I. The liability of the Company, its agents and employees for damages arising out of interruption of service or the failure to furnish service, whether caused by acts or omission, shall be limited to those remedies provided in the Public Service Commission's rules and regulations governing water utilities.

Carolina Water Service, Inc.
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2. Non-Recurring Charges

A. Water Service Connection (New connections only) - $300 per SFE

B. Plant Impact Fee (New connections only) - $400 per SFE

The Plant Capacity Fee reflects the portion of plant capacity which will be used to provide service to the new customers as authorized by Commission Rule R. 103-702.13. The plant capacity fee represents the Utility's investment previously made (or planned to be made) in constructing water production, treatment and/or distribution facilities that are essential to provide adequate water service to the new customer's property.

C. Water Meter Installation - 5/8 inches x 3/4 inches meter $45.00

All 5/8 inch x 3/4 inch water meters shall meet the Utility's standards and shall be installed by the Utility. A one-time meter fee of $35 shall be due upon installation for those locations where no 5/8 inch x 3/4 inch meter has been provided by a developer to the Utility.

For the installation of all other meters, the customer shall be billed for the Utility's actual cost of installation. All such meters shall meet the Utility's standards and be installed by the Utility unless the Utility directs otherwise.

D. Customer Account Charge – (New customers only) $30.00

A one-time fee to defray the costs of initiating service.

E. Reconnection Charges: In addition to any other charges that may be due, in those cases where a customer's service has been disconnected for any reason as set forth in Commission Rule R.103-732.5, a reconnection fee shall be due in the amount of $40.00 and shall be due prior to the Utility reconnecting service.

F. Tampering Charge: In the event the Utility's equipment, water mains, water lines, meters, curb stops, service lines, valves or other facilities have been damaged or tampered with by a customer, the Utility may charge the customer responsible for the damage the actual cost of repairing the Utility's equipment, not to exceed $250. The tampering charge shall be paid in full prior to the Utility re-establishing service or continuing the provision of service.

Carolina Water Service, Inc.
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SCHEDULE OF PROPOSED RATES AND CHARGES

SEWER

Service Territory 1 and 2
(Former customers of Carolina Water Service, Inc., Utilities Services of SC, Inc. and United Utility Companies, Inc.)

Former Customers of Carolina Water Service, Inc.

Monthly Charges – Sewer Collection & Treatment Only

Where sewage collection and treatment are provided through facilities owned and operated by the Utility, the following rates apply:

	Current	Proposed
Residential - charge per single-family house, condominium, villa, or apartment unit:	$57.58 per unit	$65.69 per unit
Mobile Homes:	$42.01 per unit	$47.94 per unit
Commercial	$57.58 per SFE*	$65.69 per SFE*

Commercial customers are those not included in the residential category above and include, but are not limited to, hotels, stores, restaurants, offices, industry, etc.

Monthly charge – Sewer Collection Only

When sewage is collected by the Utility and transferred to a government body or agency, or other entity for treatment, the Utility's rates are as follows:

Residential – per single-family house, condominium, or apartment unit	$52.93 per unit	$65.69 per unit
Commercial	$52.93 per SFE*	$65.69 per SFE*
The Village Sewer Collection	$29.95 per SFE*	$34.18 per SFE*

* Single Family Equivalent (SFE) shall be determined by using the South Carolina Department of Health and Environmental Control Guidelines for Unit Contributory Loadings for Domestic Wastewater Treatment Facilities -- 25 S.C. Code Ann. Regs. 61-67 Appendix A, as may be amended from time to time. Where applicable, such guidelines shall be used for determination of the appropriate monthly service and tap fee.

Corrected

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

TERMS AND CONDITIONS
AND
NON-RECURRING CHARGES

1. **<u>Terms and Conditions</u>**

A. Where the Utility is required under the terms of a 201/208 Plan, or by other regulatory authority with jurisdiction over the Utility, to interconnect to the sewage treatment system of a government body or agency or other entity and tap/connection/impact fees are imposed by that entity, such tap/connection/impact fees will be charged to the Utility's affected customers on a pro rata basis, without markup.

B. The Utility will, for the convenience of the owner, bill a tenant in a multi-unit building, consisting of four or more residential units (or in such other circumstances as the law may allow from time to time), which is served by a master sewer meter or a single sewer connection. However, in such cases all arrearages must be satisfied before service will be provided to a new tenant or before interrupted service will be restored. Failure of an owner to pay for services rendered to a tenant in these circumstances may result in service interruptions.

C. <u>Billing Cycle</u>
Recurring charges will be billed monthly in arrears. Non-recurring charges will be billed and collected in advance of service being provided.

D. <u>Toxic and Pretreatment Effluent Guidelines</u>
The utility will not accept or treat any substance or material that has been defined by the United States Environmental Protection Agency ("EPA") or the South Carolina Department of Health and Environmental Control ("DHEC") as a toxic pollutant, hazardous waste, or hazardous substance, including pollutants falling within the provisions of 40 CFR 129.4 and 401.15. Additionally, pollutants or pollutant properties subject to 40 CFR 403.5 and 403.6 are to be processed according to pretreatment standards applicable to such pollutants or pollutant properties, and such standards constitute the Utility's minimum pretreatment standards. Any person or entity introducing such prohibited or untreated materials into the Company's sewer system may have service interrupted without notice until such discharges cease, and shall be liable to the Utility for all damages and costs, including reasonable attorney's fees, incurred by the Utility as a result thereof.

E. <u>Extension of Utility Service Lines and Mains</u>
The Utility shall have no obligation at its expense to extend its utility service lines or mains in order to permit any customer to discharge acceptable wastewater into one of its sewer systems. However, anyone or entity which is willing to pay all costs associated with extending an appropriately sized and constructed main or utility service line from his/her/its premises to any appropriate connection point, and pay the appropriate fees and charges as set forth in this rate schedule, and comply with the guidelines and standards hereof, shall not be denied service unless sewer capacity is unavailable or unless the South Carolina Department of Health and Environmental Control or other government entity has for any reason restricted the Utility from adding additional customers to the serving sewer system.

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In no event will the Utility be required to construct additional sewer treatment capacity to serve any customer or entity without an agreement acceptable to the Utility first having been reached for the payment of all costs associated with adding wastewater treatment capacity to the affected sewer system.

F. A Single Family Equivalent ("SFE") shall be determined by 6 S.C. Code Ann. Regs. 61-67 Appendix A, as may be amended from time to time. Where applicable, such guidelines shall be used for determination of the appropriate monthly service, plant impact fee and tap fee. The Company shall have the right to request and receive water usage records from the water provider to its customers. In addition, the Company shall have the right to conduct an inspection of the customer's premises. If it is determined that actual flows or loadings are greater than the design flows or loadings, then the Company shall recalculate the customer's equivalency rating based on actual flows or loadings and thereafter bill for its services in accordance with such recalculated loadings.

G. The liability of the Company, its agents and employees for damages arising out of interruption of service or the failure to furnish service, whether caused by acts or omission, shall be limited to those remedies provided in the Public Service Commission's rules and regulations governing wastewater utilities.

2. **Solids Interceptor Tanks**

For all customers receiving sewage collection service through an approved solids interceptor tank, the following additional charges shall apply:

A. Pumping Charge
At such time as the Utility determines through its inspection that excessive solids have accumulated in the interceptor tank, the Utility will arrange for the pumping tank and will include $150.00 as a separate item in the next regular billing to the customer.

B. Pump Repair or Replacement Charge
If a separate pump is required to transport the customer's sewage from solids interceptor tank to the Utility's sewage collection system, the Utility will arrange to have this pump repaired or replaced as required and will include the cost of such repair or replacement as a separate item in the next regular billing to the customer and may be paid for over a one-year period.

C. Visual Inspection Port
In order for a customer who uses a solids interceptor tank to receive sewage service from the Utility or to continue to receive such service, the customer shall install at the customer's expense a visual inspection port which will allow for observation of the contents of the solids interceptor tank and extraction of test samples therefrom. Failure to provide such visual inspection port after timely notice of not less than thirty (30) days shall be just cause for interruption of service until a visual inspection port has been installed.

Carolina Water Service, Inc.
Docket No. 2017-292-WS
SCHEDULE OF PROPOSED RATES AND CHARGES

3. **Non-recurring Charges**

A. Sewer Service Connection (New connections only) $300 per SFE

B. Plant Capacity Fee (New connections only) $400 per SFE

The Plant Capacity Fee shall be computed by using South Carolina DHEC "Guide Lines for Unit Contributory Loadings to Wastewater Treatment Facilities" (1972) to determine the single family equivalency rating. The plant capacity fee represents the Utility's investment previously made (or planned to be made) in constructing treatment and/or collection system facilities that are essential to provide adequate treatment and disposal of the wastewater generated by the development of the new property.

The nonrecurring charges listed above are minimum charges and apply even if the equivalency rating of non-residential customer is less than one (1). If the equivalency rating of a non-residential customer is greater than one (1), then the proper charge may be obtained by multiplying the equivalency rating by the appropriate fee. These charges apply and are due at the time new service is applied for, or at the time connection to the sewer system is requested.

C. Notification Fee

A fee of $15.00 shall be charged to each customer per notice to whom the Utility mails the notice as required by Commission Rule R. 103-535.1 prior to service being discontinued. This fee assesses a portion of the clerical and mailing costs of such notices to the customers creating the cost.

D. Customer Account Charge - (New customers only)

$30.00

A one-time fee to defray the costs of initiating service. This charge will be waived if the customer is also a water customer.

E. Reconnection Charges: In addition to any other charges that may be due, in those cases where a customer's service has been disconnected for any reason as set forth in Commission Rule R. 103-532.4 a reconnection fee in the amount of $500.00 shall be due at the time the customer reconnects service. Where an elder valve has been previously installed, a reconnection fee of $40.00 shall be charged.

F. Tampering Charge: In the event the Utility's equipment, sewage pipes, meters, curb stops, service lines, elder valves or other facilities have been damaged or tampered with by a customer, the Utility may charge the customer responsible for the damage the actual cost of repairing the Utility's equipment, not to exceed $250. The tampering charge shall be paid in full prior to the Utility re-establishing service or continuing the provision of service.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 363
DOCKET NO. W-354, SUB 364
DOCKET NO. W-354, SUB 365

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-354, SUB 363 In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina, 28217, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricane Florence	)	
DOCKET NO. W-354, SUB 364 In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina, 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina	)	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE
DOCKET NO. W-354, SUB 365 In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina, 28217, for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Related to Major New Projects That Are or Will Be In-Service Prior to the Date of An Order in Petitioner's Pending Base Rate Case	)	

HEARD: Thursday, September 5, 2019, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East 4th Street, Charlotte, North Carolina

Tuesday, September 10, 2019, at 7:00 p.m., in Courtroom A, Dare County Courthouse, 962 Marshall C. Collins Drive, Manteo, North Carolina

Tuesday, October 8, 2019, at 7:00 p.m., in Courtroom #1, Watauga County Courthouse, 842 W. King Street, Boone, North Carolina

Wednesday, October 9, 2019, at 7:00 p.m., in Courtroom 1A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina

Monday, October 14, 2019, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, October 22, 2019, at 7:00 p.m., in the Superior Courtroom, Onslow County Courthouse, 625 Court Street, Jacksonville, North Carolina

Monday, December 2, 2019, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chair Charlotte A. Mitchell; and Commissioners Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, and Jeffrey A. Hughes

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

Mark R. Alson, Ice Miller LLP, One American Square, Suite 290, Indianapolis, Indiana 46282-0200

Christina D. Cress, Nichols, Choi & Lee, PLLC, 4700 Homewood Court, Suite 220, Raleigh, North Carolina 27609

For Corolla Light Community Association, Inc.:

Brady W. Allen, The Allen Law Offices, PLLC, 1514 Glenwood Ave., Suite 200, Raleigh, North Carolina 27608

For the Using and Consuming Public:

Gina C. Holt, William E. Grantmyre, John Little, and William E. H. Creech, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On January 17, 2019, in Docket No. W-354, Sub 363 (Sub 363) Carolina Water Service, Inc., of North Carolina (CWSNC or Company) filed a Petition for an Accounting Order to Defer Unplanned Incremental Hurricane Florence Storm Damage Expenses, Capital Investments, and Revenue Loss.

On May 24, 2019, pursuant to Commission Rule R1-17(a), CWSNC submitted notice of its intent to file a general rate case application in Docket No. W-354, Sub 364 (Sub 364).

On June 6, 2019, the Commission entered an order consolidating Sub 363 and Sub 364.

On June 28, 2019, CWSNC filed its verified application for a general rate increase (Application) in Sub 364 seeking authority to: (1) increase and adjust its rates for water and sewer utility service in all of its service areas in North Carolina, including the service areas of Riverbend Estates and Pace Utilities Group, Inc., which have been recently transferred to CWSNC; (2) consolidate rates for the Corolla Light/Monteray Shores (CLMS) service area with the Uniform Sewer Rate Division rates; and (3) pass through any increases in purchased bulk water rates and any increased costs of wastewater treatment performed by third parties and billed to CWSNC, all subject to CWSNC providing sufficient proof of such increases. In addition, the Company included as part of its rate case filing certain information and data required by NCUC Form W-1.

As part of the its Application CWSNC filed direct testimony of the following witnesses: Catherine E. Heigel, President of CWSNC, Tennessee Water Service, Inc., and Blue Granite Water Company;[1] Dante M. DeStefano, Director of Financial Planning and Analysis for CWSNC; Gordon R. Barefoot, President and CEO of Corix Infrastructure, Inc.;[2] J. Bryce Mendenhall, Vice President of Operations for CWSNC; Anthony Gray,

[1] On November 1, 2019, CWSNC filed notice that Donald H. Denton would adopt the prefiled direct testimony of Catherine E. Heigel.

[2] On November 8, 2019, CWSNC filed notice that Shawn Elicegui would adopt the prefiled direct testimony of Gordon R. Barefoot.

Senior Financial and Regulatory Analyst, CWSNC; and Dylan W. D'Ascendis, Director at ScottMadden, Inc.

The Company stated in its Application that it presently has approximately 34,915 water customers and 21,403 sewer customers in North Carolina (including water and sewer availability customers).[3] The present rates for water and sewer service have been in effect since February 21, 2019, pursuant to the Commission's Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase and Requiring Customer Notice issued in CWSNC's last general rate case in Docket No. W-354, Sub 360 (Sub 360 Order).

On June 28, 2019, in Docket No. W-354, Sub 365 (Sub 365), CWSNC also filed a Petition for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Relating to Major New Projects.

On July 15, 2019, the Commission issued an Order Establishing General Rate Case and Suspending Rates. By that order, the Commission declared the matter to be a general rate case pursuant to N.C. Gen. Stat. § 62-137, suspended the proposed new rates for up to 270 days pursuant to N.C.G.S. § 62-134, and established the test year period for this case as the 12-month period ending March 31, 2019.

On August 2, 2019, the Commission issued an Order Scheduling Hearings and Requiring Customer Notice (Scheduling Order) which required the parties to prefile testimony and exhibits, scheduled the matter for hearing, and required notice to all affected customers. That order scheduled customer hearings to be held in Charlotte, Manteo, Boone, Asheville, Raleigh, and Jacksonville, North Carolina, and set the expert witness hearing to be held in Raleigh, North Carolina.

Also on August 2, 2019, CWSNC witness DeStefano filed supplemental testimony, and on August 23, 2019, CWSNC filed an amended exhibit to witness DeStefano's supplemental testimony.

On August 21, 2019, CWSNC filed a certificate of service demonstrating that the Company provided notice of this general rate case proceeding to customers as required by the Commission's Scheduling Order.

On August 22, 2019, Corolla Light Community Association, Inc. (CLCA), filed a Petition to Intervene, which the Commission granted by order dated September 5, 2019.

[3] The Company did not indicate the specific date related to its present number of customers stated in the Application. The number of customers presented in Finding of Fact No. 13 herein is based on the detailed billing analysis prepared by Public Staff witness Casselberry for the 12-month period ended March 31, 2019, and is not disputed by the Company.

The Public Staff – North Carolina Utilities Commission's (Public Staff) participation in this proceeding is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

Public witness hearings were held as scheduled. A total of 23 Company customers testified as public witnesses at the public witness hearings held in this proceeding.

CWSNC responded to public witness testimony by its filings of September 25 (combined Charlotte and Manteo), October 24 (combined Boone and Asheville), October 30 (Raleigh), and November 8, 2019 (Jacksonville).

On October 4, 2019, CWSNC filed its rate case updates, schedules, and supporting data as required by Ordering Paragraph No. 6 of the Commission's Scheduling Order.

The Public Staff filed its direct testimony on November 4, 2019, consisting of testimony and exhibits of Public Staff witnesses Gina Y. Casselberry, Utilities Engineer, Water, Sewer, and Telephone Division; Charles M. Junis, Utilities Engineer, Water, Sewer, and Telephone Division; Lindsey Q. Darden, Utilities Engineer, Water, Sewer, and Telephone Division**;** Windley E. Henry, Manager, Water, Sewer, and Telephone Section, Accounting Division; Michelle M. Boswell, Staff Accountant, Accounting Division; Lynn L. Feasel, Staff Accountant, Accounting Division; and John R. Hinton, Director, Economic Research Division.

The Public Staff filed the supplemental testimony of witness Casselberry on November 15, 2019.

On November 15, 2019, the Company filed a request to consolidate Sub 365 with this rate case. The Commission issued an order consolidating Sub 364 and Sub 365 on November 19, 2019.

The Public Staff filed revised exhibits of Public Staff witnesses Feasel and Henry on November 18, 2019.

On November 18, 2019, CWSNC withdrew its request for consideration of the Company's proposed Consumption Adjustment Mechanism and Conservation Rate Pilot Program proposed for The Point Subdivision.

CWSNC filed the rebuttal testimony of Company witnesses DeStefano, Mendenhall, and D'Ascendis on November 20, 2019.

On November 26, 2019, Public Staff witness Hinton filed supplemental testimony and exhibits, revising his recommended rate of return on common equity and updating four exhibits filed with his testimony on November 4, 2019.

On November 27, 2019, CWSNC and the Public Staff (Stipulating Parties) filed a Joint Partial Settlement Agreement and Stipulation (Stipulation). On that date, the Public Staff also filed exhibits and supporting schedules for the Stipulation.

On December 2, 2019, CLCA filed a resolution opposing CWSNC's rate increase Application but requesting that CLMS' rates be set as part of CWSNC's uniform rate division.

The expert witness hearing was held as scheduled beginning on December 2, 2019. All prefiled testimony and exhibits filed in the consolidated dockets were admitted into evidence without objection. All parties agreed to waive cross-examination on all prefiled direct testimony with respect to the issues the parties resolved by Stipulation.

During the hearing the Commissioners requested certain additional information in the form of late-filed exhibits. The Public Staff filed the late-filed exhibits of Public Staff witnesses Casselberry and Henry on December 9 and 11, 2019, respectively. CWSNC filed the late-filed exhibits of Company witnesses DeStefano, D'Ascendis, and Mendenhall on December 13, 2019.

On January 10, 2020, CWSNC filed the affidavit of its Financial Planning and Analysis Manager, Matthew Schellinger, providing the updated amount of regulatory commission expense agreed to by CWSNC and the Public Staff.

On January 13, 2020, the Public Staff filed Revised Settlement Exhibits I and II providing the final expense information of CWSNC and the Public Staff's final revised recommendation.

Based upon the foregoing, including the verified Application and accompanying NCUC Form W-1, the testimony and exhibits of the public witnesses appearing at the hearings, the testimony and exhibits of the expert witnesses received into evidence, the Stipulation, and the entire record herein, the Commission makes the following:

FINDINGS OF FACT

General Matters

1. CWSNC is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. It is a franchised public utility providing water and sewer utility service to customers in 38 counties in North Carolina. CWSNC is

a wholly-owned subsidiary of Corix Regulated Utilities, Inc. (Corix),[4] previously known as Utilities, Inc.

2. CWSNC is properly before the Commission pursuant to Chapter 62 of the North Carolina General Statutes for a determination of the justness and reasonableness of its proposed rates and charges for the water and sewer utility service it provides to customers in North Carolina.

3. The appropriate test year for use in this proceeding is the 12-month period ending March 31, 2019, updated for known and measurable changes through the close of the expert witness hearing.

4. CWSNC's present rates for water and sewer service have been in effect since February 21, 2019, pursuant to the Commission's Sub 360 Order.

The Stipulation

5. On November 27, 2019, the Stipulating Parties filed the Stipulation, resolving all but two of the contested issues between CWSNC and the Public Staff in this matter.

6. The Stipulation is the product of give-and-take in negotiations between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this case along with the other evidence of record, including that submitted by the Company, the Public Staff, and the public witnesses who testified at the public witness hearings.

7. The Stipulation is a settlement of matters in controversy in this proceeding as between the Stipulating Parties and was not joined in nor objected to by CLCA, the other party to the proceeding.

8. The two remaining contested issues (Unsettled Issues) which were not resolved by the Stipulation between CWSNC and the Public Staff are:

a. Rate of return on common equity; and

b. CWSNC's request for deferred accounting treatment of certain costs related to the Automatic Meter Reading (AMR) meter installation projects in the Fairfield Mountain and Connestee Falls systems.

[4] Pursuant to the Articles of Amendment filed with the Illinois Secretary of State, Department of Business Services on July 25, 2019, Utilities Inc, changed its corporate name to Corix Regulated Utilities, Inc. Corix owns regulated utilities which provide water and sewer utility service to approximately 190,000 customers in 17 states, with primary service areas in Florida, North Carolina, South Carolina, Louisiana, and Nevada.

Acceptance of Stipulation

9. The Stipulation will provide CWSNC and its ratepayers just and reasonable rates when combined with the rate effects of the Commission's decisions regarding the Unsettled Issues in this proceeding.

10. The provisions of the Stipulation are just and reasonable to all parties to this proceeding, as well as the CWSNC ratepaying customers, and serve the public interest.

11. It is appropriate to approve the Stipulation in its entirety.

Customer Concerns and Service

12. As of the 12-month period ended March 31, 2019, CWSNC served approximately 30,724 water customers and 20,105 wastewater customers, including CLMS. For the same period, CWSNC also had 3,532 water availability customers in Carolina Forest, Woodrun, Linville Ridge, Sapphire Valley, Connestee Falls, and Fairfield Harbour; and 1,274 sewer availability customers in Sapphire Valley, Connestee Falls, and Fairfield Harbour. CWSNC operates 96 water utility systems and 37 sewer utility systems.

13. A total of 23 witnesses testified at the six public witness hearings held for the purpose of receiving customer testimony.[5] In general, public witness testimony at those hearings primarily dealt with objections to the rate increase with some customers raising concerns about quality of service, including, but not limited to, old equipment, delays in attention to meter repair, hardness of the water, digital meter boxes installed below the water table, boil water notices (including incidents and related communication), sewer spills in the lake at Connestee Falls, fluoride in the water, the ratio of base to fixed charges, response time to some inquiries, mineral content, the proposed Consumption Adjustment Mechanism, and the requirement of paying sewer charges while a home was unoccupied due to hurricane damage.

14. As of November 15, 2019, the Public Staff had received approximately 316 written customer statements of position from CWSNC customers. The service areas represented by those submitting such statements are: Belvedere (1), Brandywine Bay (2), Carolina Pines (1), Carolina Trace (11), Corolla Light/Monteray Shores (1), Connestee Falls (48), Fairfield Harbour (33), Kings Grant (1), Sapphire Valley (2), The Point (161), Treasure Cove (1), Ski Mountain (1) Waterglyn, (1) Woodhaven (1), and unspecified service areas (51).[6] All of the customers objected to the magnitude and frequency of the

[5] As noted above in the procedural history, there were no witnesses in Manteo, four in Charlotte, none in Boone, nine in Asheville, four in Raleigh, and six in Jacksonville.

[6] Approximately 80% of the customer statements came from four subdivisions or systems. Public Staff witness Casselberry testified that nearly all of the customers in The Point Subdivision opposed CWSNC's proposed Pilot Program.

Company's rate increases. Their primary concern was that CWSNC's request for another rate increase was so soon after the most recent increase was granted in February 2019. Customers were also concerned about the rate of return on common equity requested, the increase in rates compared to inflation, the impact of recent federal corporate income tax reductions, and the ratio of the base facility charge to volumetric charges. The majority of the customers in The Point Subdivision opposed CWSNC's proposed Pilot Program.[7]

15. CWSNC filed four verified reports with the Commission addressing the service-related concerns and other comments by witnesses who testified at the public witness hearings. The reports described each of the witnesses' specific service-related concerns and comments, the Company's response, and how each concern and comment was resolved or addressed, if applicable.

16. The Company's customers in the Bradfield Farms Subdivision, Brandywine Bay, and the Fairfield Harbour Service Area testified to hardness of the water and unpleasant taste, conditions that are not regulated by the North Carolina Department of Environmental Quality (DEQ).

17. It is appropriate for CWSNC to provide an estimate of the cost of installing a central water filter system for Bradfield Farms Subdivision and the Fairfield Harbour Service Area, for the homeowners' association's consideration, within 60 days of the final order in this case, as recommended by the Public Staff.[8]

18. CWSNC has continued its course of increased attention to the communications component of service to customers since the Company's last rate case, with a positive emphasis on more proactive communications and the expansion of several social media platforms.

19. The Public Staff's description of the quality of service provided by CWSNC as "good" is supported by the record in this case.

20. The overall quality of service provided by CWSNC is adequate.

[7] Public Staff witness Casselberry testified that the primary objections of customers at The Point Subdivision were that: (1) customers in The Point Subdivision were being penalized and that the block rates should apply to all CWSNC customers, (2) the average consumption did not take into account customers who live on the lake and use lake water for irrigation, (3) the covenants do not allow individual wells for irrigation, and (4) the conditions and rules for landscaping would increase the average bill by approximately 30% if the block tiered rates were approved.

[8] Public Staff witness Casselberry testified that in CWSNC's previous rate case, Sub 360, filed in 2018, the Public Staff investigated whether installing a central water filter system for Fairfield Harbour was a prudent investment. In that proceeding the Public Staff determined it was not a prudent investment because most customers had individual water softeners and filter systems in their homes and the cost in 2011 to install the system was approaching $1 million dollars. However, since it still remains an issue with customers at Fairfield Harbour and Bradfield Farms, the Public Staff recommended that if the majority of homeowners want a central water filter system, a monthly surcharge could be added to customer bills in those service areas to recover the costs for the systems.

Rate Base

21. The appropriate level of rate base used and useful in providing service is $132,897,368 for CWSNC's combined operations, itemized as follows:

Item	Amount
Plant in service	$238,212,084
Accumulated depreciation	(57,897,943)
Net plant in service	180,314,141
Cash working capital	2,404,800
Contributions in aid of construction	(40,270,675)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(5,995,444)
Customer deposits	(315,447)
Inventory	271,956
Gain on sale and flow back taxes	(417,811)
Plant acquisition adjustment	(837,878)
Excess book value	(0)
Cost-free capital	(261,499)
Average tax accruals	(143,198)
Regulatory liability for excess deferred taxes	(3,941,344)
Deferred charges	2,122,707
Pro forma plant	0
Original cost rate base	$132,897,368

Operating Revenues

22. The appropriate level of operating revenues under present rates for use in this proceeding is $33,968,582, consisting of service revenues of $33,852,232 and miscellaneous revenues of $387,492, reduced by uncollectibles of $271,142.

Maintenance and General Expense

23. The appropriate level of maintenance expense and general expense for combined operations for use in this proceeding is $14,897,501 and $6,560,142, respectively.

24. It is appropriate for CWSNC to recover total rate case expenses of $519,416 related to the current proceeding and $649,806 of unamortized rate case costs related to the prior proceedings in Docket Nos. W-354, Sub 356 (Sub 356) and W-354, Sub 360 (Sub 360).

25. It is appropriate to amortize the total rate case costs for the current and prior proceedings over five years and to include an annual level of costs in the amount of

$73,911 related to miscellaneous regulatory matters, resulting in an annual level of rate case expense of $307,755, as agreed to by the Stipulating Parties.

Storm Reserve Fund and Normalized Storm Damage Expense

26. It is reasonable and appropriate for CWSNC to include in rates an annualized level of storm expenses in its maintenance and repair expense, based on a ten-year average of the Company's actual storm costs. This is the first general rate case proceeding in which CWSNC has sought Commission approval of a normalized level of storm expenses to be included in base rates. As part of the Stipulation CWSNC and the Public Staff agreed that CWSNC would rescind its request for a storm reserve fund and that the calculation of normalized storm damage expense would be based on a ten-year average of the Company's actual storm costs rather than utilizing the Company's requested three-year average.

27. The appropriate annual amount of normalized storm costs that should be included in the Company's rates in this case is $34,567, as set out in the Stipulation.

Hurricane Florence Expense

28. It is reasonable and appropriate for CWSNC to include in rates the incremental operating and maintenance (O&M) costs amounting to $146,773 incurred by the Company related to Hurricane Florence.

29. The Company and the Public Staff have agreed to use deferral accounting treatment for Hurricane Florence storm-related expenses, which will be amortized over three years.

30. It is appropriate to include in the Company's maintenance and repair expense Hurricane Florence storm-related costs in the amount of $48,924, as set out in the Stipulation.

Deferral of Wastewater Treatment Plant and AMR Meter Installation Projects

31. In its Petition for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Relating to Major New Projects in Sub 365 CWSNC requested deferral accounting treatment for post-in-service depreciation expense and financing costs (carrying costs) related to the Connestee Falls wastewater treatment plant (WWTP) project in Buncombe County; the Nags Head WWTP project in Dare County; the Fairfield Mountain AMR meter installation project in Transylvania County; and the Connestee Falls AMR meter installation project, also in Buncombe County.

32. During the test year for this rate case CWSNC earned a return on equity per books of 1.63% on a consolidated basis. The Company's current rates were set in the Sub 360 rate case effective for service rendered on and after February 21, 2019, based upon an authorized rate of return on common equity of 9.75%. CWSNC invested

approximately $22 million of additional capital in its North Carolina water and sewer systems since the Sub 360 rate case, which served to depress its post-test year earned rate of return on common equity.

33. Each of the four capital projects covered by the Petition requesting deferral accounting treatment was completed and placed in service prior to the expert witness hearing in these proceedings. As evidenced by the Stipulation, CWSNC and the Public Staff agreed to the Company's deferral of incremental post-in-service depreciation expense and financing costs of the two WWTP projects and to the amount of the costs to be included in the rate case.

34. The Public Staff did not agree to deferral accounting treatment for the incremental post-in-service depreciation expense and return on capital expenditures relating to the two AMR meter installation projects.

35. In this case the two WWTP projects subject to the Company's deferral request were prudent and necessary to the provision of service, and the costs for each of those projects were reasonable and prudently incurred. CWSNC and the Public Staff agree that the Company should be authorized to defer post-in-service costs of $1,098,778 for the two WWTP projects ($520,144 for Connestee Falls and $578,634 for Nags Head). CWSNC and the Public Staff also agree that the rate of return on common equity impact is 434 basis points for the Uniform Sewer Rate Division.

36. The project costs for each of the two WWTP projects, considered both collectively and singularly, are unusual or extraordinary in that they represent major capital investments in the Company's infrastructure; they are non-routine projects which are of considerable complexity and major significance; and they are necessary to CWSNC's provision of safe, adequate, reliable, and affordable utility service in this state. The WWTP costs are of a magnitude that would have an adverse material impact on the Company's financial condition if they are not afforded deferral accounting treatment.

37. It is reasonable and appropriate for CWSNC to receive deferral accounting treatment for the post-in-service depreciation expense and carrying costs related to the Company's capital investments in the WWTPs placed in service at Nags Head and Connestee Falls during the pendency of this proceeding.

38. The Company should be authorized to defer and amortize post-in-service depreciation expense and carrying costs in the amount of $1,098,778 related to its capital investments in the Nags Head and Connestee Falls WWTPs for the ten- and eight-month periods, respectively, from their in-service dates until the projects are included for recovery in base rates, as stipulated between CWSNC and the Public Staff. These costs should be amortized over a period of five years.

39. CWSNC expects significant ongoing capital needs at levels comparable to the $22 million additional capital it invested in its North Carolina water and sewer systems since the Sub 360 rate case. Deferral accounting treatment for the post-in-service costs

related to the two WWTPs is appropriate to support the Company's ability to earn its authorized return and, as a result, could impact CWSNC's ability to finance needed investments on reasonable terms. Accordingly, deferral accounting treatment for the two WWTP costs will have a favorable impact on CWSNC's earnings and financial standing in general thereby enhancing the Company's ability to access and obtain capital on favorable terms and such results will accrue to the benefit of the Company's customers as well as to its investors.

40. The two AMR meter installation projects included in CWSNC's deferral accounting request were prudent and the costs for the installation were reasonable and prudently incurred. CWSNC and the Public Staff agree that the rate of return on common equity impact is 24 basis points for the Uniform Water Rate Division.[9] CWSNC and the Public Staff also agree that the requested cost deferral amount related to the AMR meter installation costs is $64,736 for the eight-month period from their in-service dates until the projects are included for recovery in base rates in this case.

41. The two AMR meter installation projects in the Fairfield Mountain and Connestee Falls service areas are not unusual or extraordinary, and thus the incremental post-in-service depreciation expense and carrying costs related to the two projects are not appropriate for deferral accounting treatment.

Depreciation and Amortization Expense

42. The appropriate level of depreciation and amortization expense for combined operations for use in this proceeding is $5,026,554.

Franchise, Property, Payroll, and Other Taxes

43. The appropriate level of franchise, property, payroll, and other taxes for use in this proceeding is $795,507 for combined operations, consisting of ($655) for franchise and other taxes, $268,734 for property taxes, and $527,428 for payroll taxes.

Regulatory Fee and Income Taxes

44. It is reasonable and appropriate to calculate regulatory fee expense using the regulatory fee rate of 0.13% effective July 1, 2019, pursuant to the Commission's June 18, 2019 Order issued in Docket No. M-100, Sub 142. The appropriate level of regulatory fee for use in this proceeding is $44,159.

[9] Calculated on a rate division basis, per Public Staff DeStefano Cross-Examination Exhibit 2. The total company ROE impact is 13 basis points as shown on Public Staff witness Henry Late-Filed Exhibit 4, Line 9.

45. It is reasonable and appropriate to use the current North Carolina corporate income tax rate of 2.50% to calculate CWSNC's revenue requirement. The appropriate level of state income taxes for use in this proceeding is $75,474.

46. It is reasonable and appropriate to use the federal corporate income tax rate of 21.00% to calculate CWSNC's revenue requirement. The appropriate level of federal income taxes for use in this proceeding is $618,133.

47. It is appropriate to calculate income taxes for ratemaking purposes based on the adjusted level of revenues and expenses and the tax rates for utility operations.

The Federal Tax Cuts and Jobs Act

48. CWSNC's federal protected EDIT should continue to be flowed back in accordance with the Reverse South Georgia Method (RSGM) as ordered by the Commission in the Sub 360 Order.

49. It is reasonable and appropriate, for purposes of this proceeding, for CWSNC to refund its remaining federal unprotected EDIT balances over 24 months instead of the remaining 35 months as originally ordered by the Commission in the Sub 360 Order.

50. CWSNC's North Carolina EDIT recorded pursuant to the Commission's May 13, 2014 Order Addressing the Impacts of HB 998 on North Carolina Public Utilities issued in Docket No. M-100, Sub 138 should continue to be amortized in accordance with the Commission's Sub 356 Order.

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

51. The cost of capital and revenue increase approved in this order is intended to provide CWSNC, through sound management, the opportunity to earn an overall rate of return of 7.39%. This overall rate of return is derived from applying an embedded cost of debt of 5.36%, and a rate of return on common equity of 9.50%, to a capital structure consisting of 50.90% long-term debt and 49.10% common equity.

52. A 9.50% rate of return on common equity for CWSNC is just and reasonable in this general rate case.

53. A 49.10% equity and 50.90% debt ratio is a reasonable and appropriate capital structure for CWSNC in this case.

54. A 5.36% cost of debt for CWSNC is reasonable and appropriate for the purpose of this case.

55. Any increase in the Company's rate for service will be difficult for some of CWSNC's customers to pay, in particular for those considered to be low-income customers.

56. Continuous safe, adequate, reliable, and affordable water and wastewater utility service by CWSNC is essential to CWSNC's customers.

57. The rate of return on common equity and capital structure approved by the Commission appropriately balances the benefits received by CWSNC's customers from CWSNC's provision of safe, adequate, and reliable water and wastewater utility service with the difficulties that some of CWSNC's customers will experience in paying the Company's increased rates.

58. The 9.50% rate of return on common equity and the 49.10% equity capital structure approved by the Commission balance CWSNC's need to obtain equity and debt financing with its customers' need to pay the lowest possible rates.

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

Revenue Requirement

60. CWSNC's rates should be changed by amounts which, after all pro forma adjustments, will produce the following increases in revenues:

Item	Amount
CWSNC Uniform Water	$ 1,778,015
CWSNC Uniform Sewer	2,929,386
BF/FH/TC Water	96,561
BF/FH Sewer	141,797
Total	$4,945,759

These increases will allow CWSNC the opportunity to earn a 7.39% overall rate of return, which the Commission has found to be reasonable upon consideration of the findings in this order.

Rate Design

61. Regarding the CLMS sewer service area, CWSNC has maintained the CLMS system at the same rates for the last four general rate cases (Docket No. W-354, Subs 336, 344, 356, and 360) in order to allow the remainder of the Uniform Sewer Rate Division to move toward parity with the CLMS sewer rates. In this proceeding the Company proposes to consolidate the CLMS sewer service area rates with the Uniform

Sewer Rate Division rates, as the total Uniform Sewer revenue requirement is currently sufficient to allow for such consolidation of rate structures. It is reasonable and appropriate at this time to consolidate the CLMS sewer service area rates with the Company's Uniform Sewer rates. This rate design is supported by both the Public Staff and CLCA.

62. It is reasonable and appropriate for CWSNC's rate design for water utility service for its Uniform Water and Bradfield Farms/Fairfield Harbour/Treasure Cove (BF/FH/TC) Water residential customers to be based on a 50/50 ratio of base charge to usage charge, and to use an 80/20 ratio of base charge to usage charge for CWSNC's Uniform Sewer residential customers, as set out in the Stipulation.

63. The rates and charges included in Appendices A-1 and A-2, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto as Appendices B-1 and B-2, are just and reasonable and should be approved.

Water and Sewer System Improvement Charges

64. Consistent with Commission Rules R7-39(k) and R10-36(k), CWSNC's WSIC and SSIC surcharges will reset to zero as of the effective date of the approved rates in this proceeding.

65. Pursuant to N.C.G.S. § 62-133.12, the cumulative maximum charges that the Company can recover between rate cases cannot exceed 5% of the total service revenues approved by the Commission in this rate case.

Recommendations of the Public Staff

66. It is reasonable and appropriate for the Company, in its next general rate case filing, to ensure that its NCUC Form W-1, Item 26 has been carefully reviewed so that the filing does not include double bills, that the Company accounts for multi-unit customers, and that other bills produced, such as final bills, late notices, re-bills, or other miscellaneous bills, are not included in the filing.

67. It is reasonable to approve an increase in the Company's reconnection fee from $27.00 to $42.00.

68. The connection charge of $1,080 for water and $1,400 for sewer for Winston Pointe Subdivision, Phase IA, recommended by the Public Staff is reasonable and appropriate.

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

General Matters

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings are informational, procedural, and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5–11

The Stipulation and Acceptance of Stipulation

The evidence supporting these findings of fact is found in the Stipulation, the testimony of both CWSNC's and the Public Staff's witnesses, the affidavit of Matthew Schellinger, and Revised Settlement Exhibits I and II.

On November 27, 2019, CWSNC and the Public Staff entered into and filed a Partial Settlement Agreement and Stipulation, which memorializes their agreements on some of the issues in this proceeding. Attached to the Stipulation is Settlement Exhibit 1, which demonstrates the impact of the Stipulating Parties' agreements on the calculation of CWSNC's gross revenue for the test year ended March 31, 2019. Thus, the Stipulation is based upon the same test period as the Company's Application, adjusted for certain changes in plant, revenues, and costs that were not known at the time the case was filed, but are based upon circumstances occurring or becoming known through the close of the expert witness hearing. In addition to the Stipulating Parties' agreements on some of the issues in this proceeding, the Stipulation provides that CWSNC and the Public Staff agree that the Stipulation reflects a give-and-take partial settlement of contested issues, and that the provisions of the Stipulation do not reflect any position asserted by either CWSNC or the Public Staff, but instead reflect compromise and settlement between them. The Stipulation provides that it is binding as between CWSNC and the Public Staff, and that it is conditioned upon the Commission's acceptance of the Stipulation in its entirety. No party filed a formal statement or presented testimony indicating opposition to the Stipulation. During the expert witness hearing in response to a question from the Commission, CLCA indicated that it has no objection to the Stipulation. Tr. vol. 9, 200–01. There are no other parties to this proceeding.

The key aspects of the Stipulation are as follows:

- ***Tariff Rate Design*** – The Stipulating Parties agree that rate design in this case should be based on a 50/50 ratio of fixed/volumetric revenues for the Uniform Water and BF/FH/TC Water residential customers and an 80/20 ratio of fixed/volumetric revenues for the Uniform Sewer residential customers.

- ***Capital Structure*** – The Stipulating Parties agree that the capital structure appropriate for use in this proceeding is a capital structure consisting of 49.10% common equity and 50.90% long-term debt at a cost of 5.36%.

- ***Property Insurance Expense*** – The Stipulating Parties agree to the Company's rebuttal position of $279,912.

- ***Treatment of Water Service Corporation (WSC) Rent Expense*** – The Stipulating Parties agree to the Public Staff's calculation of WSC's rent expense for its Chicago, Illinois office lease as reflected in Revised Feasel Exhibit I, Schedule 3-11.

- ***Water Loss Adjustment for Purchased Water Expense*** – The Stipulating Parties agree upon a 20% water loss threshold for Whispering Pines, Zemosa Acres, Woodrun, High Vista, and Carolina Forest subdivisions.

- ***Purchase Acquisition Adjustment (PAA) Amortization Expense Rates*** – The Company agrees to the Public Staff's PAA amortization rates per Revised Feasel Exhibit I, Schedule 3-15.

- ***Storm Reserve Fund and Storm Expense*** – The Company agrees to rescind its request to implement its proposed Storm Reserve Fund, and to utilize the Public Staff's position per Revised Feasel Exhibit I, Schedule 3-4.

- ***Application of Hurricane Florence Insurance Proceeds*** – The Public Staff agrees to the Company's rebuttal position removing insurance overpayments to date from the insurer.

- ***Accumulated Deferred Income Taxes (ADIT)*** - The Company agrees to the Public Staff's proposed calculations of ADIT regarding unamortized rate case expense. The Stipulating Parties agree to revise ADIT for any updates made to rate case expense deferrals.

- ***Deferral Accounting for Capital Investments in WWTPs -*** The Stipulating Parties agree that deferral accounting treatment for post-in-service depreciation expense and carrying costs related to the Company's capital investments in WWTPs placed in service at Nags Head and Connestee Falls during the pendency of this proceeding is reasonable and appropriate.

- ***Regulatory Commission Expense*** - The Stipulating Parties agree to a methodology for calculating regulatory commission expense, also known as rate case expense, and agreed to update the number in Settlement Exhibit 1, Line 41, for actual and estimated costs once supporting documentation is provided by the Company. The Stipulating Parties agreed to amortize rate case expenses for a five-year period.

- ***Revenue Requirement*** – The Stipulating Parties agree to certain other revenue requirement issues designated as “Settled Items” on Settlement Exhibit 1, which was attached to the Stipulation and is incorporated by reference therein.

As the Stipulation has 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. *CUCA II*, 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 [C]hapter 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 17.

Based upon the foregoing and the entire record herein, the Commission finds that the Stipulation was entered into by the Stipulating Parties after full discovery and extensive negotiations, that the Stipulation is the product of give-and-take in settlement negotiations between CWSNC and the Public Staff, and that the Stipulation represents a reasonable and appropriate resolution of certain specific matters in dispute in this proceeding. In making this finding the Commission gives substantial weight to the testimony of CWSNC witness DeStefano and the testimony and supporting exhibits of Public Staff witnesses Henry and Feasel which support the Stipulation, and notes that no party expressed opposition to the provisions of the Stipulation. In addition when the provisions of the Stipulation are compared to CWSNC's Application and the recommendations included in the testimony of the Public Staff’s witnesses, the Stipulation results in a number of downward adjustments to the expenses sought to be recovered by CWSNC, and resolves issues, some of which were more important to CWSNC and, others of which were more important to the Public Staff. Therefore, the Commission further finds that the Stipulation is material evidence to be given appropriate weight in this proceeding, along with all other evidence of record, including that submitted by CWSNC, the Public Staff, CLCA, and the public witnesses who testified at the hearings.

In addition, the Commission finds that the Stipulation is a nonunanimous settlement of matters in controversy in this proceeding and that the Stipulation resolves only some of the disputed issues between CWSNC and the Public Staff. The Stipulation leaves the following Unsettled Issues to be resolved by the Commission: (1) rate of return on common equity; and (2) the deferral of expenses related to the installation of AMR meters in the Company's Fairfield Mountain and Connestee Falls service areas.

After careful consideration the Commission finds that when combined with the rate effects of the Commission's decisions regarding the foregoing Unsettled Issues, the Stipulation strikes a fair balance between the interests of CWSNC to maintain its financial strength at a level that enables it to attract sufficient capital on reasonable terms, on the one hand, and its customers to receive safe, adequate, reliable, and affordable water and sewer service at the lowest reasonably possible rates, on the other. The Commission finds that the resulting rates are just and reasonable to both CWSNC and its ratepayers. In addition, the Commission finds that the provisions of the Stipulation are just and reasonable to all parties to this proceeding and serve the public interest, and that it is appropriate to approve the Stipulation in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-20

Customer Concerns and Service

The evidence supporting these findings of fact is found in the testimony of the public witnesses appearing at the hearings, in the testimony of Public Staff witness Casselberry, in the testimony and exhibits of CWSNC witnesses DeStefano and Mendenhall, and in the verified reports filed by CWSNC in response to the concerns testified to by the public witnesses at hearings.

On June 28, 2019, CWSNC filed an application for a general rate increase, which was verified by CWSNC's Financial Planning and Analysis Manager. The Application stated that CWSNC presently serves approximately 34,915 water customers and 21,403 sewer customers in North Carolina. The Company's service territory spans 38 counties in North Carolina, from Corolla in Currituck County to Bear Paw in Cherokee County.

The Commission held hearings throughout CWSNC's service territory for the purpose of receiving testimony from members of the public, and particularly from CWSNC's water and wastewater customers, as follows:

Hearing Date	Location	Public Witnesses
September 5, 2019	Charlotte	William Colyer, Rachel Fields, William Michael Wade, and James Sylvester
September 10, 2019	Manteo	None
October 8, 2019	Boone	None
October 9, 2019	Asheville	Chuck Van Rens, Jack Zinselmeier, Jeff Geisler, Phil Reitano, Jeannie Moore, Linda Huber, Brian McCarthy, Ron Shuping, and Steve Walker
October 14, 2019	Raleigh	Alfred Rushatz, Vince Roy, Mark Gibson, and David Smoak
October 22, 2019	Jacksonville	Danny Conner, Ralph Tridico, James C. Kraft, John Gumbel, David Stevenson, and Irving Joffee

Public Staff witness Casselberry testified that her investigation included a review of customer complaints, contact with the DEQ Division of Water Resources (DWR) and Public Water Supply Section (PWSS), review of Company records, and analysis of revenues at existing and proposed rates. Tr. vol. 8, 78. Witness Casselberry testified that she contacted the seven regional offices in North Carolina. The PWSS identified four water systems – Riverwood, Meadow Glen, Wood Trace, and Sapphire Valley – which required action by CWSNC; DWR identified three wastewater treatment plants – CLMS, Carolina Trace, and Asheley Hills – which required action by CWSNC. Witness Casselberry investigated each concern and testified that CWSNC has taken the necessary actions and that the Public Staff is satisfied that the concerns reported by PWSS and DWR have been addressed or are in the process of being resolved. Tr. vol. 8, 81.

In addition, witness Casselberry testified that she had reviewed approximately 316 consumer statements of position from CWSNC customers received by the Public Staff as a result of this proceeding. Witness Casselberry stated that the service areas represented by those submitting statements are Belvedere (1), Brandywine Bay (2), Carolina Pines (1), Carolina Trace (11), Corolla Light/Monteray Shores (1), Connestee Falls (48), Fairfield Harbour (33), Kings Grant (1), Sapphire Valley (2), The Point (161), Treasure Cove (1), Ski Mountain (1), Waterglyn (1), Woodhaven (1), and unspecified service areas (51). Tr. vol. 8, 96. She testified that all customers objected to the magnitude of the rate increase. She indicated that public witnesses' primary concern was that CWSNC's request for another rate increase was filed just four months after it had been granted an increase in rates in February 2019. Most of the customers in Connestee Falls said there was no justification for such a large increase, that they had to pay the base charge for service when they were not occupying their homes, and that they experienced numerous leaks and boil water advisory notices over the summer. The customers in Fairfield Harbour said that they were still recovering from Hurricane Florence and that they could not afford an increase. They also stated that the water quality was poor and that they had to install individual softeners and filter systems. Nearly all of the customers in The Point Subdivision opposed CWSNC's proposed Pilot Program. Their primary objections were that (1) customers in The Point were being penalized, and that the block rates should apply to all CWSNC customers, (2) the average consumption did not take into account customers who live on the lake and use lake water for irrigation, (3) the covenants do not allow individual wells for irrigation, and (4) the conditions and rules for landscaping would increase the average bill by approximately 30 percent if the block tiered rates were approved. Tr. vol. 8, 96–101. Customer concerns were addressed in Public Staff witness Casselberry's supplemental testimony filed on November 15, 2019.

Witness Casselberry also testified regarding service and water quality complaints registered by customers at each of the five public hearings. Tr. vol. 8, 111. She stated that she had read each of the four reports filed by CWSNC in response to the customer concerns and complaints which were included in testimony at the public hearings. Witness Casselberry testified that there were a few isolated service issues which the Company had addressed or was in the process of resolving.

After reviewing the testimony and complaints of the customers regarding water quality and hardness in the Fairfield Harbour and Bradfield Farms service areas, witness Casselberry stated CWSNC should provide an estimate of the cost of installing a central water filter system for Bradfield Farms Subdivision, Tr. vol. 8, 102–03, and the Fairfield Harbour Service Area, Tr. vol. 8, 109–110, for the homeowners' associations' consideration.

With the exception of her recommendation for Bradfield Farms Subdivision and the Fairfield Harbour Service Area, witness Casselberry had no additional comments or recommendations. Tr. vol. 8, 111. She testified that CWSNC's quality of service is good. Tr. vol. 8, 111. Witness Casselberry also testified that the quality of water meets the standards set forth by the Safe Drinking Water Act and is satisfactory. Tr. vol. 8, 111.

With regard to the concerns expressed by customers about the Company's proposed Pilot Program to test conservation rates in The Point Subdivision, the Commission acknowledges that this matter is no longer an issue in this proceeding because CWSNC withdrew its request for authority to implement its proposed Pilot Program on November 18, 2019. CWSNC stated its withdrawal of the Pilot Program was based on the Public Staff's opposition to CWSNC's proposed Pilot Program in the present case and the existence of the Commission's generic rate design proceeding in Docket No. W-100, Sub 59 (Sub 59). CWSNC noted that the Company will continue to actively participate in the Commission's Sub 59 generic rate design proceeding to explore and consider rate design proposals that may better achieve the Company's desire for revenue sufficiency and stability, while also sending appropriate signals to consumers that support and encourage water efficiency and conservation.

Additionally, in CWSNC's November 18, 2019 filing, the Company withdrew its request for the consumption adjustment mechanism (CAM) proposed in this proceeding. CWSNC stated its withdrawal for the CAM was prompted by the Commission's initiation of a rulemaking proceeding in Docket No. W-100, Sub 61 on November 14, 2019; the Public Staff's testimony in this matter recommending that the Commission deny CWSNC's request to implement a CAM; and the Company's expectation that other water and wastewater providers will seek to have input on the implementation of any CAM guidelines. CWSNC maintained that the contested issues concerning the requested CAM are more suitable for resolution in the generic proceeding than in this rate case proceeding.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearings, the Company's reports on customer comments, the Public Staff's engineering and service quality investigation, and the late-filed exhibits submitted by CWSNC and the Public Staff, the Commission concludes that, consistent with the statutory requirements of N.C.G.S. § 62-131(b), the overall quality of service provided by CWSNC is adequate, efficient, and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Rate Base

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Company witness DeStefano, the testimony of Public Staff witnesses Feasel and Henry, the Stipulation, and Revised Settlement Exhibits I and II.

The following table summarizes the differences between the Company's level of rate base from its Application and the amounts recommended by the Public Staff:

Item	Company Per Application	Difference	Amount Per Public Staff
Plant in service	$217,460,239	$20,751,845	$238,212,084
Accumulated depreciation	($55,739,757)	($2,158,186)	($57,897,943)
Net plant in service	161,720,483	18,593,659	180,314,141
Cash working capital	2,467,676	(62,876)	2,404,800
Contributions in aid of construct.	(40,916,105)	645,430	(40,270,675)
Advances in aid of construction	(32,940)	0	(32,940)
Accum. deferred income taxes	(6,699,939)	704,495	(5,995,444)
Customer deposits	(304,114)	(11,333)	(315,447)
Inventory	271,956	0	271,956
Gain on sale and flow back taxes	(131,695)	(286,116)	(417,811)
Plant acquisition adjustment	(873,734)	35,856	(837,878)
Excess book value	(331)	331	0
Cost-free capital	(261,499)	0	(261,499)
Average tax accruals	125,013	(268,211)	(143,198)
Regulatory liability for EDIT	(3,941,344)	0	(3,941,344)
Deferred charges	2,252,645	(129,938)	2,122,707
Pro forma plant	17,195,228	(17,195,228)	0
Original cost rate base	$130,871,300	$2,026,068	$132,897,368

On the basis of the Stipulation and revisions made by the Public Staff in its Revised Settlement Exhibits I and II, the Company and the Public Staff are in agreement concerning all components of rate base except for the amount of cash working capital. Therefore, the Commission finds that the uncontested adjustments to rate base recommended by the Public Staff are appropriate adjustments to be made in this proceeding.

CWSNC and the Public Staff disagree on the amount of cash working capital to include in rate base for use in this proceeding due to the unsettled issue concerning the deferral accounting treatment of the AMR meter installation projects in Fairfield Mountain and Connestee Falls. Based on the testimony of Company witness DeStefano, CWSNC disagrees with the Public Staff's recommendation to deny deferral accounting treatment for the two AMR meter installation projects. As a result of their differing positions concerning this issue and its effect on their respective recommended level of maintenance and repair expense, CWSNC and the Public Staff recommend different amounts for cash working capital to include in rate base, $2,406,418 and $2,404,800, respectively.

Based on the conclusions reached elsewhere in this order concerning the deferral accounting treatment for AMR meter installation projects in Fairfield Mountain and Connestee Falls, the Commission concludes that the appropriate amount for cash working capital is $2,404,800. Consequently, the appropriate level of rate base for combined operations for use in this proceeding is as follows:

Item	Amount
Plant in service	$238,212,084
Accumulated depreciation	($57,897,943)
Net plant in service	180,314,141
Cash working capital	2,404,800
Contributions in aid of construction	(40,270,675)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(5,995,444)
Customer deposits	(315,447)
Inventory	271,956
Gain on sale and flow back taxes	(417,811)
Plant acquisition adjustment	(837,878)
Excess book value	0
Cost-free capital	(261,499)
Average tax accruals	(143,198)
Regulatory liability for excess deferred taxes	(3,941,344)
Deferred charges	2,122,707
Pro forma plant	0
Original cost rate base	$132,897,368

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

Operating Revenues

The evidence supporting this finding of fact is found in the testimony of Public Staff witnesses Feasel and Casselberry, and Company witness DeStefano. The following table summarizes the differences between the Company's level of operating revenues under present rates from its Application and the amounts recommended by the Public Staff:

Item	Company per Application	Difference	Amount per Public Staff
Operating Revenues:			
Service revenues	$33,269,517	$582,715	$33,852,232
Miscellaneous revenues	353,280	34,212	387,492
Uncollectible accounts	(246,348)	(24,794)	(271,142)
Total operating revenues	$33,376,449	$592,133	$33,968,582

Based on the Stipulation and the revisions made by the Public Staff in its Feasel Revised Exhibits I and II, the Company does not dispute the following Public Staff adjustments to operating revenues under present rates:

Item	Amount
Reflect pro forma level of service revenues	$582,715
Adjustment to forfeited discounts	10,128
Adjustment to sale of utility property	24,084
Adjustment to uncollectible accounts	(24,794)
Total	$592,133

For reasons discussed elsewhere in this order, the Commission has found that the adjustments listed above are appropriate adjustments to be made to operating revenues under present rates in this proceeding.

Based on the foregoing, the Commission concludes that the appropriate level of operating revenues under present rates for combined operations for use in this proceeding is as follows:

Item	Amount
Service revenues	$33,852,232
Miscellaneous revenues	387,492
Uncollectible accounts	(271,142)
Total operating revenues	$33,968,582

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-25

Maintenance and General Expenses

The evidence for these findings of fact is found in the verified Application and the accompanying NCUC Form W-1; the testimony of Public Staff witnesses Feasel, Henry, and Darden; the testimony of Company witnesses DeStefano and Mendenhall; the affidavit of Matthew Schellinger; and the Revised Settlement Exhibits I and II.

The following table summarizes the differences between the Company's requested level of maintenance and general expenses and the amounts recommended by the Public Staff:

Item	Company Per Application	Difference	Amount Per Public Staff
Maintenance Expenses:			
Salaries and wages	$5,143,430	($193,719)	$4,949,710
Purchased power	2,110,722	(7,679)	2,103,043
Purchased water & sewer	2,171,965	47,278	2,219,243
Maintenance and repair	2,955,315	165,620	3,120,935
Maintenance testing	546,264	(1,832)	544,432
Meter reading	206,176	0	206,176
Chemicals	713,452	(19,856)	693,596
Transportation	539,115	(4,915)	534,200
Operating expenses charged to plant	(615,663)	(49,470)	(665,133)
Outside services - other	1,219,715	(28,417)	1,191,299
Total maintenance expenses	$14,990,492	($92,991)	$14,897,501
General Expenses:			
Salaries and wages	$2,386,901	($382,491)	$2,004,409
Office supplies and other office expense	569,400	(536)	568,864
Regulatory commission expense	303,485	4,269	307,754
Pension and other benefits	1,531,096	69,062	1,600,158
Rent	392,552	(62,244)	330,308
Insurance	664,043	118,519	782,562
Office utilities	751,728	(4,058)	747,670
Miscellaneous	355,931	(137,513)	218,417
Total general expenses	$6,955,135	($394,993)	$6,560,142

Regulatory Commission Expense

In his January 10, 2020 affidavit, Matthew Schellinger provided an amount of $519,416 for the actual costs incurred to date and the estimated expense to be incurred related to this rate case. Affiant Schellinger requested that the Commission approve total rate case costs of $1,169,222 to be amortized over five years. He stated that the $1,169,222 includes $649,806 for unamortized rate case expense from prior proceedings plus $519,416 related to this case. Affiant Schellinger commented that the annual amortization expense for rate case costs for this proceeding total $233,844 ($1,169,222 amortized over five years). Affiant Schellinger also requested that the Commission include in regulatory commission expense an annual amount of $73,911 in miscellaneous regulatory costs for filings and compliance type activities not directly related to rate case costs. He maintained that these expenses are a direct cost of service, are not disputed, and were agreed upon between CWSNC and the Public Staff in the Stipulation. In sum, Affiant Schellinger requested that the Commission include a total annual amount of

$307,755 in regulatory commission expense in this proceeding, consisting of rate case costs of $233,844 and miscellaneous regulatory costs of $73,911.

The Public Staff stated that it has reviewed the invoices and other supporting documents along with the rate case expense spreadsheet provided by CWSNC and found that the types of rate case expense in this rate case matched the nature of the expense in prior rate cases and the amount of these expenses in the current proceeding are appropriate and reasonable to be included in this rate case. The Public Staff and the Company are in agreement that the miscellaneous regulatory matters costs in the Company's books as provided in the affidavit of Matthew Schellinger should also be included as regulatory commission expense to be recovered in this rate case as a reasonable cost of service incurred by CWSNC. Therefore, in light of the foregoing the Commission finds that it is appropriate and reasonable to amortize the sum of the total rate case costs of $519,416 for the current proceeding and the unamortized rate case cost balance of $649,806 from the prior rate cases over five years and to include an annual level of costs in the amount of $73,911 related to miscellaneous regulatory matters, resulting in an annual level of regulatory commission expense of $307,755 to be recovered in this proceeding.

On the basis of the Stipulation and revisions made by the Public Staff in Henry Revised Exhibit I, Feasel Revised Exhibits I and II, and Revised Settlement Exhibits I and II, the Company and the Public Staff are in agreement concerning all adjustments recommended by the Public Staff to maintenance and general expenses except for maintenance and repair expense. Therefore, the Commission finds that the uncontested adjustments to maintenance and general expenses recommended by the Public Staff are appropriate adjustments to be made in this proceeding.

CWSNC and the Public Staff disagree on the amount of maintenance and repair expense to include in maintenance and general expenses in this proceeding due to the unsettled issue concerning the deferral accounting treatment of the AMR meter installation projects in Fairfield Mountain and Connestee Falls. Based on the testimony of Company witness DeStefano, CWSNC disagrees with the Public Staff's recommendation to deny deferral accounting treatment for the two AMR meter installation projects. As a result of their differing positions concerning this issue, CWSNC and the Public Staff recommend differing amounts for maintenance and repair expense, $3,133,882[10] and $3,120,935, respectively. The Company included an amount of $12,947 ($64,736 amortized over five years) in maintenance and repair expense related to its requested deferral accounting treatment for the two AMR meter installation projects whereas the Public Staff did not.

Based on the conclusions reached elsewhere in this Order concerning the deferral accounting treatment for the AMR meter installation projects in Fairfield Mountain and

[10] See page 160 of the Company's proposed order filed on January 10, 2020, in these dockets which includes the agreed-upon pro forma adjustments per the Stipulation and CWSNC's recommendations concerning the two unsettled issues in this rate case.

Connestee Falls, the Commission concludes that the appropriate level of maintenance and repair expense for combined operations for use in this proceeding is $3,120,935.

Based upon the foregoing, the Commission concludes that the appropriate level of maintenance and general expenses for combined operations for use in this proceeding are as follows:

Item	Amount
Maintenance Expenses:	
Salaries and wages	$4,949,710
Purchased power	2,103,043
Purchased sewer	2,219,243
Maintenance and repair	3,120,935
Maintenance testing	544,432
Meter reading	206,176
Chemicals	693,596
Transportation	534,200
Operation exp. charged to plant	(665,133)
Outside services - other	1,191,299
Total maintenance expenses	$14,897,501
General Expenses:	
Salaries and wages	$2,004,409
Office supplies and other office expense	568,864
Regulatory commission expense	307,754
Pension and other benefits	1,600,158
Rent	330,308
Insurance	782,562
Office utilities	747,670
Miscellaneous	218,417
Total general expenses	$6,560,142

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-27

Storm Reserve Fund and Normalized Storm Damage Expense

The evidence for these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Public Staff witnesses Feasel and Henry, and the Stipulation and Revised Settlement Exhibits I and II.

In the Company's Application, it requested to establish a storm reserve fund to support extraordinary O&M costs resulting from damages sustained in severe storms such as Hurricane Florence. CWSNC witness DeStefano testified that CWSNC proposes to create a monthly, flat surcharge for each active customer's water and sewer service bill until the reserve threshold of $250,000 is reached. Witness DeStefano commented that CWSNC proposed to collect a monthly surcharge of $0.42 per customer per month based on the threshold of $250,000. In addition, this is the first general rate case proceeding in which CWSNC seeks Commission approval of a normalized level of storm expenses to be included in base rates. In NCUC Form W-1, Item 10, Schedule 24, the Company used three years (2016–2018) to calculate the average storm cost requested to be recovered in this rate case. Witness DeStefano maintained that the storm reserve fund would only be utilized if the Company's storm costs for the last 12 months exceed the level of normalized storm expenses included in the base rate revenue requirement.

Public Staff witness Henry testified that in addition to the storm reserve fund, CWSNC applied to include in rates a normalized level of storm expense calculated using a three-year average of actual storm expenses incurred, excluding Hurricane Florence expenses. Witness Henry stated that ten years has historically been used to calculate the average storm cost because a ten-year time period would include some years in which storm costs were high and others in which they were low, resulting in a more reasonable average than that which would result from using only the three most recent years. Additionally, witness Henry stated that using a ten-year time period has been approved by the Commission in prior decisions. For the reasons set forth in his prefiled testimony, witness Henry recommends that the Commission deny CWSNC's request for a storm reserve fund. In the Stipulation the Company agreed to rescind its request to implement its proposed storm reserve fund and also agreed to the Public Staff's use of a ten-year average for storm costs. The Stipulating Parties have agreed to a normalized level of storm expenses in the amount of $34,567, to be included in maintenance and repair expense.

Therefore, in light of the foregoing the Commission concludes that it is appropriate and reasonable to continue its historical practice of using a ten-year time period as the standard for calculating average annualized storm costs to be recovered in the Company's rates as an ongoing level of expense. Consequently, the appropriate annual level of normalized storm costs that should be included in CWSNC's rates in this proceeding is $34,567, as set out in the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-30

Hurricane Florence Expense

The evidence supporting these findings of fact is found in the Company's Petition for Accounting Order in Sub 363, the testimony of Company witness DeStefano, the testimony of Public Staff witnesses Henry and Feasel, the Stipulation, Settlement Exhibit I, and Revised Settlement Exhibits I and II in Sub 364.

On January 17, 2019, CWSNC filed a Petition for an Accounting Order to Defer Unplanned Incremental Hurricane Florence Storm Damage Expenses, Capital Investments, and Revenue Loss in Sub 363 requesting an accounting order authorizing it to establish a regulatory asset and defer until the Company's next general rate case costs incurred in connection with damage to the Company's water and wastewater systems resulting from the impacts of Hurricane Florence. Additionally, the Company sought Commission approval to defer O&M costs, lost revenues, and depreciation expense on its capital investments. According to the Sub 363 Petition, CWSNC's facilities suffered extensive damage due to the storm, particularly in the coastal region of the Company's service territory.

CWSNC stated that it incurred extraordinary, unplanned operating and capital costs, as well as lost revenues from customers who were forced to disconnect their service due to damage to their homes. Additionally, the Company provided invoices to the Public Staff showing that it has incurred, to date, $146,773 in storm-related incremental O&M expenses, $582,570 in capital investments, and $46,320 in estimated revenue loss. In its comments filed on April 4, 2019, the Public Staff did not object to CWSNC's recovery of a substantial portion of its 2018 verified storm O&M costs and deferral accounting treatment for the incremental O&M costs related to Hurricane Florence; however, it opposed CWSNC's request to defer depreciation expense associated with the Company's capital investments and lost revenues. Additionally, the Public Staff recommended that the amortization period begin as of October 2018, the date of the storm, and not begin with the effective date of the Company's next general rate case, which is the instant case, Sub 364, filed on June 28, 2019.

After considering prior cases and the tests applied by the Commission, the Public Staff determined that "the damage to CWSNC's system from Hurricane Florence was greater than that caused by any other storm in the Company's history, which will affect the Company's rate of return on common equity. The Public Staff concluded that this is an exceptional circumstance justifying some deferral of costs." Public Staff's Sub 363 Comments. However, in opposing CWSNC's request to defer depreciation expense associated with the Company's capital costs and lost revenues, the Public Staff cited the Commission's order in the last Duke Energy Progress, LLC. (DEP), general rate case, Docket No. E-2, Sub 1142, where DEP's request for deferral of depreciation expense, return on the undepreciated balance of capital costs, and the carrying costs on the entirety of the deferred costs was denied.

The Public Staff, therefore, recommends the following:

(a) that the Commission approve a deferral of $146,773 in 2018 Hurricane Florence storm O&M expenses, but no deferral of CWSNC's depreciation expense or lost revenues;
(b) that CWSNC be required to amortize the costs deferred over a three-year period beginning in October 2018;
(c) that upon final determination of the actual amount of costs of Hurricane Florence the Company be required to file a final accounting of said costs with the Commission for review and approval;
(d) that approval of this accounting procedure is without prejudice to the right of any party to take issue with the amount of or the ratemaking treatment accorded these costs in any future regulatory proceeding; and
(e) that any applicable insurance proceeds received by CWSNC will be used to offset the deferred O&M expenses.

As shown in Settlement Exhibit I, witness Feasel calculated a total deferral amount of $146,773 for the incremental O&M costs related to the 2018 storm costs with an amortization period of three years beginning in October 2018, using the procedure recommended by witness Henry. The Company and the Public Staff agree to the amount of Hurricane Florence storm-related costs included in Settlement Exhibit I as noted in the Stipulation.

The Commission finds and concludes that it is just and reasonable for the Company to receive deferral accounting treatment for the incremental O&M costs amounting to $146,773 in Hurricane Florence storm costs and that these costs should be amortized over three years. Consequently, it is appropriate to include in CWSNC's maintenance and repair expense Hurricane Florence storm-related costs in the amount of $48,924, as set out in the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-41

Deferral of WWTP Projects and AMR Meter Installation Projects

The evidence for these findings of fact is found in the record of Sub 365, including the initial comments of the Public Staff and the reply comments of the Company; the testimony of Company witnesses DeStefano and Mendenhall; the testimony and exhibits of Public Staff witnesses Henry, Feasel, and Junis; the Stipulation, and Revised Settlement Exhibits I and II.

Summary of the Evidence

On June 28, 2019, contemporaneously with the Sub 364 rate case application, the Company filed a Petition for an Accounting Order to Defer Post-In-Service Depreciation and Financing Costs Relating to Major New Projects in Sub 365.

On September 20, 2019, the Public Staff filed comments, and on October 21, 2019, CWSNC filed reply comments. On November 15, 2019, the Company filed a motion to consolidate the Sub 365 docket with the Sub 364 rate case proceeding, which was granted by Commission order dated November 19, 2019.

In its Sub 365 petition, CWSNC describes four major new projects that were in progress and would be placed in service after the close of the test year but during the pendency of this general rate case proceeding. The Company requests authority to defer the incremental post-in-service depreciation expense and financing costs of those projects and then to recover those costs in the rates approved in Sub 364, amortized over a five-year period. The four projects are:

(a) Connestee Falls WWTP in Buncombe County;
(b) Nags Head WWTP in Dare County;
(c) Fairfield Mountain AMR meters installed in Transylvania County; and
(d) Connestee Falls AMR meters installed in Buncombe County.

CWSNC witness DeStefano's testimony explained that the accounting and cost recovery treatment of these projects would have a material impact on the Company's ability to earn its authorized return from its last rate case. The Company requests deferral of incremental post-in-service depreciation expense and financing costs on these four projects from their respective in-service dates until the projects are included for recovery in base rates in this case.

Company witness Mendenhall described the four projects. He stated that the Connestee Falls WWTP project involved the installation of a “sequencing batch reactors” treatment facility which replaced a 300,000 gallons per day (gpd) concrete plant installed in the early 1970s. He noted that the plant is located in the mountains and exposed to winter weather, including cold, ice, and snow. These conditions led to the serious erosion of exposed areas of concrete, most significantly the above-the-waterline walls and walkways, due to years of “freeze/thaw” cycles. Witness Mendenhall maintained that the concrete deterioration had reached the point of “end of life” of the asset and that the old plant presented a high risk of failure. He stated that the build-out needs of the community require 460,000 gpd of wastewater treatment capacity and that the new plant was built adjacent to the existing plant. He commented that the cost of the project was $7,177,326 and that it was placed in-service on July 31, 2019.

Witness Mendenhall testified that the Nags Head WWTP project consisted of the installation of a new membrane treatment facility to allow for effluent disposal below permitted nitrate levels in groundwater monitoring wells. He explained that the purpose of this project was to modify the existing Aeromod 0.400 million gallon per day (mgd) plant with membrane filtration to provide reuse-quality effluent to meet groundwater nitrate and total dissolved solids (TDS) compliance testing limits. Witness Mendenhall noted that in 2018, the Division of Water Quality, DEQ, issued a Notice of Violation requiring the plant to comply with current groundwater testing limits of 500 mg/L for TDS and 5 mg/L for nitrates. He stated that the previous plant met the wastewater treatment plant effluent limits but was unable to meet the newly imposed groundwater limits for the monitoring wells. Witness Mendenhall maintained that had the new facility not been constructed, the risk of imposition of severe penalties or a consent decree was high. He noted that the cost of the project was $6,876,116, and it was placed in-service on May 31, 2019.

Witness Mendenhall further stated that in 2019, CWSNC continued to expand its AMR meter footprint in its mountain systems. He commented that approximately 2,500 AMR meters were installed in the Connestee Falls and Fairfield Mountain Subdivisions. Witness Mendenhall testified that benefits of AMR meter technology to customers and the Company include: (1) customer satisfaction with data and billing accuracy; (2) improved customer service; (3) reduction in re-read/re-billing; (4) employee safety, especially during hazardous weather events; (5) replacement of inaccurate meters which can improve non-revenue water percentages; and (6) customer interaction with respect to personal consumption habits and trends. He noted that while AMR technology would be beneficial to CWSNC customers across the state, the mountain area systems, in particular, benefit due to the extreme weather events and related safety hazards that are common in this region. Witness Mendenhall testified that the Connestee Falls and

Fairfield Mountain AMR meter installation projects were completed by July 31, 2019, at a total cost of $880,209.

At the time this rate case and CWSNC's deferral accounting Petition were filed Company witness DeStefano estimated that implementing these four projects would create a material drag on the consolidated Company's earned rate of return on common equity of 193 basis points. Witness DeStefano testified that the Company included in its rate case filing both a calculation of the deferral balances and proposed amortizations of the deferrals, as well as a pro forma adjustment relating to O&M savings that will result from the implementation of the AMR meter projects[11]. Public Staff witness Darden confirmed in her testimony that the Company included in this rate case proceeding a pro forma adjustment of $21,000 to remove the meter reading expense for the Fairfield Mountain and Connestee Falls water systems because AMR meters do not require an operator to read each meter individually.

According to Public Staff witness Henry, all of the foregoing projects were completed and in service as of the date of the expert witness hearing as verified by Public Staff witness Casselberry, and final invoices were reviewed by the Public Staff. Tr. vol. 8, 172.

In its Sub 365 comments, the Public Staff recommended that the requested deferral accounting treatment with respect to the cost of the WWTPs at Nags Head and Connestee Falls be granted and that the requested deferral accounting treatment with respect to the AMR meters installed in Fairfield Mountain and Connestee Falls be denied in its entirety.

The Public Staff commented that in its Order Approving Deferral Accounting with Conditions in Docket No. E-7, Sub 874, the Commission stated:

> [T]he Commission has historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly. That is due, in part, to the fact that deferral accounting, typically, provides for the future recovery of costs for utility services provided to ratepayers in the past; and . . . the longer the deferral period, the greater the likelihood that the ratepayers who are ultimately required to pay rates including the deferred charges, which are related to resources consumed by the utility in providing services in earlier periods, may not be the same ratepayers who received the services. The Commission has also been reluctant to allow deferral accounting because it, typically, equates to single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recovery

[11] See NCUC Form W-1, Item 10, Schedules 26 and 34, filed June 28, 2019.

> process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges.

Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred From the Purchase of a Portion of Saluda River's Ownership in the Catawba Nuclear Station*, No. E-7, Sub 874, at 24 (N.C.U.C. Mar. 31, 2009) (DEC Sub 874 Order).

In addition the Public Staff noted that in its Order Approving in Part and Denying in Part Request for Deferral Accounting in Docket No. E-7, Sub 1029, the Commission stated, "In determining whether to allow deferral requests, the Commission has consistently and appropriately based its decision on whether, absent deferral, the costs in question would have a material impact on the company's financial condition, and in particular, the company's achieved level of earnings." Order Approving in Part and Denying in Part Request for Deferral Accounting, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant, the Dan River Natural Gas Combined Cycle Generating Plant, and the Capacity-Related Modifications at the McGuire Nuclear Generating Plant,* No. E-7, Sub 1029, at 12-13 (N.C.U.C. Apr. 3, 2013).

Thus, the Public Staff maintained that the Commission's receptivity to deferral requests is not unlimited or without regard for traditional ratemaking principles. Rather, the Public Staff stated that the Commission requires a clear and convincing showing that the costs in question were of an unusual or extraordinary nature and that, absent deferral, the costs for which deferral was requested would have a material impact on the Company's financial condition.

In determining whether to grant a deferral request the Public Staff noted that the Commission analyzes the impact the costs would have on currently achieved earnings of the utility. The Public Staff stated that the appropriate test and criteria are as follows:

> The impact on earnings, typically, has been measured and assessed in terms of ROE, considered in conjunction with (1) the return on equity (ROE) realized and (2) the company's currently authorized ROE. Also . . . current economic conditions; the Company's need for new investment capital; and the impact that the Commission decision will have on future availability and cost of such capital are also relevant to the appropriate resolution of matters of this nature. Additionally, whether the company has requested or is contemplating requesting a general rate increase and the timing, or proposed timing, of the filing of such a request is also pertinent.

DEC Sub 874 Order at 26.

The Public Staff stated in its Sub 365 comments that it had evaluated the deferrals requested in CWSNC's petition against the above criteria. Based on these criteria and other Commission decisions, the Public Staff supported deferral accounting treatment for the costs related to the WWTP projects at Nags Head and Connestee Falls. The Public Staff based its recommendation on the fact that (1) costs for the WWTPs were related to major construction projects that, at the time the Sub 365 comments were filed, were not yet in service but expected to be completed and in operation prior to the date of the expert witness hearing in this general rate case; (2) the deferral accounting request was made contemporaneously with the filing of the rate case application; and (3) the deferral period would not be so long as to cause undue concern that the ratepayers who pay rates including the deferred WWTP costs during the deferral period may not be the same ratepayers who receive service from the WWTPs. Sub 365 Comments at 6–7. Additionally, the Public Staff stated that "the impact of the costs, if not deferred, on the Company's rate of return on common equity of 9.75% approved in the Sub 360 Rate Case, will be significant. Without deferral, the Company's earnings can be expected to decline due to the WWTPs becoming plant in service." *Id*. at 7. Thus, the Public Staff contended that the WWTPs at Nags Head and Connestee Falls presented the kind of circumstances in terms of nature, impact, and timing for which deferral accounting treatment is appropriate.

Moreover, as evidenced by the Stipulation filed on November 27, 2019, the Company and the Public Staff are in agreement that the Company's request to defer incremental post-in-service depreciation expense and financing costs of the WWTPs at Nags Head and Connestee Falls is appropriate and have agreed that the Company should be authorized to defer its costs of $1,098,778 related to its WWTPs, and these costs should be amortized over five years, for an annual amount to be included in rates of $219,756.

With respect to the Public Staff's recommendation that the Commission deny deferral accounting treatment for the AMR meters installed in Fairfield Mountain and Connestee Falls, the Public Staff stated it used the same criteria for evaluating the Company's request for deferral of the WWTPs and the AMR meter costs and concluded that CWSNC's request for deferral of the AMR meter costs should be denied. Witness Henry contended that CWSNC failed to make a clear, complete, and convincing showing, in view of the entire record, that the costs of the AMR meters are of an unusual or extraordinary nature and, absent deferral, will have a material impact on the Company's financial condition. In his direct testimony, witness Henry referred the Commission to the Public Staff's initial comments filed on September 20, 2019 in Sub 365.

In its Sub 365 initial comments, the Public Staff contended that meter replacement of any kind (AMR, AMI, traditional, etc.) is not an extraordinary or unusual project but should be considered routine and as part of a properly planned and managed meter replacement program. The Public Staff stated that water meters have an industry recognized 10- to 20-year useful life before degradation of functionality and accuracy necessitate replacement. Additionally, the Public Staff stated that CWSNC has water meters in service that range in age and condition, and that it is not unusual for a water and sewer utility to undertake, during one time period, to replace a large number of aged meters in an entire subdivision or service area because doing so promotes efficiency of time and cost. Due to the nature of meter replacement being an expected and usual occurrence, the Public Staff stated that the only different or unusual aspect of the Company’s replacement project is the increased cost of the new AMR meters over the cost of analog meters. The Public Staff further noted that although the Company stated that the upgraded technology will benefit the Company and the customers, the Company’s decision to upgrade does not change the nature of the typical and expected meter replacement project. The Public Staff maintained that the increased cost of AMR meters and the number of meters replaced is the result of management decisions within CWSNC’s control and a failure of the Company to implement a systematic and measured meter replacement program.

On cross-examination witness Henry confirmed that the Public Staff's accounting investigation did not raise any prudency issues with respect to the costs incurred by the Company to complete the AMR meter installation projects, that the Public Staff did not recommend any significant disallowance of any part of these costs for ratemaking purposes, that this is the third rate case in which the Company has included costs for AMR meters for its mountain systems, and that the Public Staff did not raise any objections or questions about the prudency of the installations or of the costs of prior AMR meter installations in the previous two cases. He also agreed that deferred accounting is one way to address the issue of regulatory lag faced by a utility.

Further, witness Henry agreed that the $22 million in additional investment made by the Company since its last rate case is a significant amount of investment of capital for a company the size of CWSNC and that those investments result in regulatory lag, depending on the timing of the investments and when those investments are incorporated for recovery in rates. He also updated his estimate of earnings erosion that would occur if CWSNC's request for deferral of costs related to AMR meter installation projects is denied based upon the Company’s updated project costs. He testified that the Company's rate of return on common equity for the Uniform Water Rate Division would be negatively impacted by 24 basis points if the Commission denies deferral accounting treatment for the AMR meter installation projects. Witness Henry testified that he added the AMR meter installation projects to the rate case model that was used to calculate the gross revenue and overall rate of return allowed by the Commission in the Sub 360 Rate Order. Witness Henry stated that by including the AMR meter installation projects in that model for the Uniform Water Rate Division the rate of return on common equity granted in the Sub 360 case was decreased from 9.75% to 9.51%, a decrease of 24 basis points. Tr. vol. 8, 180. Witness Henry maintained that it was appropriate to evaluate the rate of return on common equity impact at the Rate Division level because CWSNC has four separate rate divisions: Uniform Water, Uniform Sewer, BF/FH/TC Water, and BF/FH Sewer. He stated that each of these rate divisions has a separate rate base, revenues, expenses, and rate of return. Tr. vol. 8, 217–18. Witness Henry further stated that rates have not been established on a total company basis in this rate case nor in prior rate cases filed by CWSNC.

Witness Henry agreed that, in addition to the basis point impact on rate of return on common equity, the Commission has considered the actual earned rate of return on common equity of the utility requesting deferral accounting when addressing whether non-deferral of project costs would have a material negative impact on a company's financial condition. Further, he agreed that the Commission considers deferral requests on a case-by-case basis.

On cross-examination Public Staff witness Junis expanded upon witness Henry's conclusion that the Company's AMR meter installation projects did not meet the Commission's criteria for deferral accounting. He maintained that the projects were not unusual or extraordinary because they were the result of a business choice by the Company to install AMR meter technology. Tr. vol. 8, 191. He stated that the Company could have installed traditional meters rather than AMR meters. Witness Junis testified that meter replacement should be a part of normal business. Further, he stated that AMR meters are not providing service to customers or improving service to customers and thus they are not integral to providing service. Tr. vol. 8, 198. Witness Junis distinguished AMR meters from new electricity generation investments or wastewater treatment plant investments, stating that the latter are integral to providing quality service. *Id.*

Witness Junis discounted CWSNC's claim that the Company is underearning because the underearning took place primarily under previously set rates, before the current rates were established by the last rate order in Sub 360. Tr. vol. 8, 205. Witness Junis contended that for this reason, the test period would not be the "proper window to look at when considering are they under-earning or over-earning" for purposes of the Commission's test to determine whether deferral accounting is appropriate. Tr. vol. 8, 205–06. He testified that the utility decides when it files rate cases; the Company's management decides how much consequence of regulatory lag it can accept and financially tolerate between rate cases. Tr. vol. 8, 195.

On cross-examination, witness Junis acknowledged that the Public Staff's position is that AMR meter installation projects are not eligible for cost recovery in WSIC proceedings because the WSIC statute calls for "in-kind" replacements. Witness Junis testified that the Public Staff does not consider AMR meters as in-kind with regard to differing kinds of meters. Tr. vol. 8, 195–96. He further testified that both deferral accounting and the WSIC and SSIC statute minimize regulatory lag for cost-recovery purposes. He agreed that the fact that the AMR meter installation projects do not qualify for WSIC treatment is worth considering in the context of a deferral accounting request. However, he testified that it should not be a major factor in the determination and ultimately this fact did not change the Public Staff's position that deferral should be denied.

Witness DeStefano presented rebuttal testimony explaining the appropriateness of deferral accounting treatment for the Company's two AMR meter installation projects. First, he testified that major technological upgrades such as the Company's AMR meter projects are the type of projects for which deferral accounting is appropriate. He noted that the Company's AMR meter program involves the mass replacement and technological upgrade of aged analog meters in certain targeted geographical areas, as opposed to the typical individual meter replacements that occur due to aging or damaged individual meters. He emphasized that this AMR meter program differs dramatically from individual and routine meter replacements in scope, scale, purpose, and financial impact. Witness DeStefano generally testified that the large-scale meter replacement at issue was undertaken to improve service through efficiencies, safety, and advanced technology, and that the project benefitted customers by saving some costs associated with manual meter reading and reducing system water loss. He further testified that the Company would face significant adverse impact if either the four projects subject to the petition to defer or the AMR meter projects alone were not afforded deferral accounting treatment. He explained that the Company's current overall rate of return of 7.75% authorized by the Commission in Sub 360 was not being achieved and that the Company's consolidated actual earned overall return during the test year for the instant rate case was only 3.69%.

Witness DeStefano maintained that the Public Staff's proposed rejection of deferral accounting for the two AMR meter installation projects, as well as the inability of the Company to recover the costs of depreciation and a return on the full investment of AMR meters in a WSIC filing, has the effect of significantly penalizing the Company through denial of timely cost recovery for investments in modernizing its water system operations. Witness DeStefano contended that if the Company's cost recovery for AMR meters is limited solely to a final decision in a general rate case, with no interim deferral accounting, the Company's earnings will be materially affected to its detriment. He reported that other state regulatory commissions have authorized deferral accounting in connection with meter replacement projects although he did not state whether such deferrals related specifically to the deferral of post-in-service depreciation expense and carrying costs from the AMR meter replacement projects in-service dates until the projects are included for recovery in base rates as requested by CWSNC in its petition.

Witness DeStefano urged the Commission to consider the collective financial impact of the four projects, noting that the Commission has previously considered projects on a collective basis when making deferral accounting determinations. Witness DeStefano commented that in the DEC Sub 874 Order, the Commission authorized a utility to use deferred accounting combining costs for two projects, wherein it allowed deferral accounting for both an environmental compliance cost project and the purchase of a portion of a nuclear facility on the grounds that the authorized rate of return on common equity would be eroded due to the rate of return on common equity impact of costs of 114 basis points — 67 for the environmental costs and 47 points for the facility purchase. In its reply comments CWSNC maintained that when considering the four major new projects together, the financial impact to the total Company earnings would be materially adverse, having a rate of return on common equity impact of 187 total basis points.[12]

[12] See updated Schedule 1 attached to CWSNC's reply comments filed on October 21, 2019 in Sub 365. In its Petition filed on June 28, 2019 CWSNC calculated a rate of return on common equity impact of 193 basis points for the four major new projects on a total Company basis.

Finally, witness DeStefano argued that even if the Commission were to evaluate the WWTP and the AMR meter projects separately, the rate of return on common equity impact of the AMR meter costs would still have an adverse material effect on the Company's earnings, and, thus, deferral accounting for the meter projects is merited – particularly given the Company's current underearning position. Witness DeStefano stated that given the Company's size and current underearning status, a 20-basis point AMR meter impact for the Uniform Water Rate Division[13] is unquestionably material to the Company.

During cross-examination Company witness DeStefano was questioned about Public Staff DeStefano Cross-examination Exhibit 1, which contained witness DeStefano's responses to Public Staff Data Request No. 81. Witness DeStefano confirmed that the Company had sought and received rate recovery in its Docket No. W-354, Sub 344 (Sub 344) rate case for AMR meter installation projects that occurred in 2015 in seven systems. The evidence presented confirmed that the Company's Sub 344 rate increase included the costs of 1,157 AMR meters for a total cost of over $1.2 million, and in the Company's Sub 356 rate case, CWSNC received rate recovery for AMR meter installation projects in three systems, including 2,440 meters, for a total cost of over $1.8 million. Tr. vol. 9, 158–59. Witness DeStefano also confirmed that the Company planned to complete eight similar projects over the next four years, including nearly 4,000 AMR meter replacements. Witness DeStefano further confirmed that the Company has already completed ten AMR meter projects, including 3,597 meters at a total capital cost of over $3 million, prior to the two projects presented in this case at a cost of less than $900,000.

Upon further questioning by the Public Staff witness DeStefano explained why CWSNC requested deferral accounting for two AMR meter projects at issue, but not for its previous AMR meter projects. He explained that the AMR meter projects currently being made are part of a much larger overall capital investment by the Company. He noted that in prior years overall capital investments made by the Company were in the $10 million per year range, versus $20 million invested in the current year. As a result, according to witness DeStefano, the deferral accounting request is due in part to the additional regulatory lag impact being experienced by the Company beyond the impact of the AMR meter projects alone. Additionally, he testified that the two AMR meter installation projects for which deferral accounting treatment is currently requested are larger than every meter system previously installed.[14] He explained that installing AMR meters in these two systems in this one year and trying to gain the efficiencies of completing the projects this year increases the financial implications to the Company and the significance of the projects to the Company. In summary witness DeStefano testified that with the magnitude of the capital spending CWSNC anticipates over the next few

[13] During the expert witness hearing, witness DeStefano agreed with Public Staff witness Henry's calculation of a 24-basis point negative impact on CWSNC's earned rate of return on common equity for the Uniform Water Rate Division if deferral accounting treatment for the AMR meter projects is not approved by the Commission.

[14] Company witness Mendenhall added that the 2,500 AMR meters at issue represent about 40% of the total AMR meters installed and about 8% of CWSNC's total meters in service in the State.

years to address aging system needs, the Company is looking for ways to mitigate the effect of regulatory lag on earned returns.

Discussion and Conclusions

In its Sub 365 Petition CWSNC has requested that the Commission enter an accounting order allowing the Company to defer certain post-in-service costs that were incurred in connection with two WWTP projects and two AMR meter installation projects. The related costs for which the Company seeks deferral include the incremental post-in-service depreciation expense and cost of capital (financing costs) from their respective in-service dates until the projects are included for recovery in base rates in this case. According to the evidence of record, the amounts of such costs with respect to the WWTP projects and the AMR meter installation projects are $1,098,778 and $64,736, respectively. The Company contends that the financial impact of these costs is material and would, absent deferral, equate to a significant basis point reduction in the Company's rate of return on common equity. Evidence submitted by the Public Staff confirmed that such projects when included in plant in service would individually equate to a 434-basis point rate of return on common equity reduction for the WWTPs and a 24-basis point rate of return on common equity reduction for the AMR meter installation projects for the Uniform Sewer Rate Division and the Uniform Water Rate Division, respectively. No party has suggested that either the WWTP projects or the AMR meter installation projects are imprudent in any way. Moreover, the Company and the Public Staff are in agreement regarding the amount of costs included in plant in service in this proceeding for the WWTP projects and the AMR meter installation projects.

Under the Company's proposal the costs in question would not be charged against revenues realized during the accounting period in which the costs were actually incurred. Rather, such costs would be deferred and accumulated in a regulatory asset account. As a result, the deferred costs, in effect, would be specifically reserved for recovery prospectively. The period over which the costs would be accumulated in a regulatory asset account would begin when the assets were placed in service and end on the date the Company is authorized to begin charging rates reflecting the inclusion of the WWTPs and the AMR meter installation projects in CWSNC's water and wastewater cost of service. Consequently, approval of CWSNC's deferral and cost recovery proposal would ultimately result in a level of rates, to be charged prospectively, that would specifically include an allowance providing for the recovery of the present deferred costs. On the other hand, if the request for deferral is denied, the Company would then be required to recognize the costs for which it seeks deferral as items of expense in the period in which they were incurred. In this instance, the Company would then be required to recognize those costs during a period in which it contends it is already significantly under-recovering its Commission-authorized return.

Deferral accounting should only be used sparingly as an exception to the general rule that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges. DEC Sub 874 Order at 24. Deferral is not favored, in part, because deferral accounting typically provides for the future recovery of costs for utility services provided to ratepayers in the past. The Commission has also been reluctant to allow deferral accounting because it typically equates to single-issue ratemaking for the period of deferral. *Id.* The Commission acknowledges that considering an increase in one or a few expense items in isolation, without considering reductions in other costs, brings with it the increased risk of over-recovery. However, the Commission gives significant weight in this instance that the consolidation of the Sub 365 petition for deferral accounting with the Sub 364 general rate case means that the concern regarding single-issue ratemaking and the related risk of such over-recovery should be reduced and of lesser concern because all revenues and expenses will have been examined close in time to any possible deferral.

While deferral accounting must not be used routinely or frequently, the Commission has found that an exception can be made when the costs at issue “were reasonably and prudently incurred, unusual or extraordinary in nature, and of a magnitude that would result in a material impact on the Company's financial position (level of earnings).” Order Denying Request to Implement Rate Rider and Schedule Hearing to Consider Request for Creation of Regulatory Asset Account, *Application of Duke Energy Carolinas, LLC, for Approval of Rate Rider to Allow Prompt Recovery of Costs Related to Purchases of Capacity Due to Drought Conditions,* No. E-7, Sub 849, at 19 (N.C.U.C. June 2, 2008) The Commission has, over the years, on infrequent but appropriate occasions, approved requests proposing the use of deferral accounting. Such requests, by necessity, must be examined and resolved on a case-by-case fact-specific basis and will be approved only where the Commission is persuaded by clear and convincing evidence that the costs in question are unusual or extraordinary in nature and that, absent deferral, would have a material impact on the utility's financial condition. *Id. See also,* Order Approving Deferral Accounting with Conditions*, Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred From the Purchase of a Portion of Saluda River’s Ownership in the Catawba Nuclear Station,* No. E-7, Sub 874 (N.C.U.C. Mar. 31, 2009); Order Approving Deferral Accounting, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Buck Natural Gas Combined Cycle Generating Plant and the Bridgewater Hydro Generating Plant*, No. E-7, Sub 999 (N.C.U.C. June 20, 2012) (DEC Sub 999 Order); Order Approving Deferral and Amortization, *Request by Duke Power, A Division of Duke Energy Corporation for Approval of Accounting Treatment,* No. E-7, Sub 776 (Dec. 28, 2004).

In determining whether the costs sought to be deferred or the events or circumstances leading to the costs are of such an unusual or extraordinary nature as to justify an exception to the rule against allowing deferral accounting treatment, the Commission historically examines the record for clear and convincing evidence that the costs in question represent major non-routine, infrequent, non-regularly occurring investments of considerable complexity and significance or were beyond the control of the utility such as storm costs or new operating requirements/standards imposed by newly-enacted legislation or other governmental action. *See,* Order Approving Deferral Accounting, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer*

Certain Environmental Compliance Costs at Unit 5 of the Cliffside Steam Station, No. E-7, Sub 966 at 10 (N.C.U.C. June 27, 2011); *Order Ruling on Petition,* Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer 2009 and 2010 Non-Fuel Energy Costs Excluded from Cost Recovery in the Commission's August 6, 2010 Order in Docket No. E-7, Sub 934, No. E-7, Sub 967, at 14-15 (N.C.U.C. June 14, 2011); *Order Approving in Part and Denying in Part Request for Deferral Accounting,* Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant, the Dan River Natural Gas Combined Cycle Generating Plant, and the Capacity-Related Modifications at the McGuire Nuclear Generating Plant, No. E-7, Sub 1029, at 13, 15 (N.C.U.C. April 3, 2013); Order Adopting and Amending Rules, *Rulemaking Proceeding to Implement G.S. 62-110.8,* No, E-100, Sub 150 at 22 (November 16, 2017).

In certain circumstances the Commission may find that the magnitude or level of the costs requested for deferral make the costs major, non-routine, or extraordinary. In some cases, the Commission has looked to determine whether costs were unanticipated, unplanned, beyond the control of the utility, and of an infrequent, non-recurring nature; that is, whether the costs and the circumstances of the costs are sufficiently unusual or extraordinary to warrant deferral accounting treatment – a tool not to be used routinely but sparingly as discussed above. Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of Amended Schedule NS,* No. E-22, Sub 517, at 11–12 (N.C.U.C. Mar. 29, 2016). A finding that the magnitude of the costs supports a determination that they are unusual or extraordinary may not, in some circumstances also support a finding that these costs, if not deferred, will have a material adverse impact on the company's financial condition to warrant deferral accounting treatment. In determining whether deferral or non-deferral will have a material impact on the company's financial condition while the Commission may consider other matters, it often examines whether and to what extent the costs incurred will have a significant impact on the level of company earnings and the company's ability to achieve its currently authorized rate of return on common equity. DEP Sub 874 Order at 25–26. In determining materiality, while the Commission may consider other matters, it often examines whether and to what extent the costs incurred will have a significant impact on the level of company earnings and the company's ability to achieve its currently authorized rate of return on common equity. *Id.*

With regard to the WWTP projects, the Commission is persuaded that the costs are of an unusual, extraordinary nature. Both the Company and the Public Staff also agree that the costs associated with the WWTP projects are unusual or extraordinary in nature, as the Commission has used those terms in previous deferral accounting orders and as those terms are commonly understood. The Commission observes as stated in a previous deferral accounting case, *"[t]he costs in question are unusual or extraordinary in the sense that they are associated with the incorporation of the costs of two [WWTP] facilities – representing major investments – into the Company's rate structure; which is not a simple, regularly occurring, inconsequential event, but rather, is a major non-routine matter of considerable complexity and major significance."* DEC Sub 999 Order, at 18. In the present proceeding, the evidence demonstrates that the WWTP projects were not an everyday, regular occurrence but were in fact non-routine, complex, and of major significance and that the associated costs are similarly unusual or extraordinary. The WWTP projects involved the installation of new treatment facilities that were integral to providing wastewater utility service and that were necessitated by conditions causing the old facilities to present unacceptable risks of failure and inability to comply with environmental requirements exposing the company to the further high risk of severe penalties and imposition of a consent decree. Such circumstances and replacement of such major facilities that are at risk of both functional and environmental compliance failure do not occur on a frequent basis.

The Commission is likewise persuaded that absent deferral, the costs will have a material impact on the Company's financial condition. The evidence demonstrates that the Company is not meeting its currently authorized rate of return on common equity and that even if the Sub 360 rate increase had been in effect for a full year, the rate of return on common equity impact of the costs of the WWTP projects would have an adverse impact on the Company's financial condition. The Commission gives significant weight to the undisputed testimony of witness DeStefano that CWSNC's consolidated actual earned rate of return on common equity during the test year for this rate case (the 12-month period ended March 31, 2019) was 1.63%. The Commission further finds credible the evidence that the rate increase in the last rate case was approximately $1.1 million, which would not make up the difference from an actual rate of return on common equity of 1.63% to 9.75%, CWSNC's authorized rate of return on common equity granted in the Sub 360 Rate Order. Further, the evidence shows that the WWTP investments of approximately $14 million would result in a 434-basis point rate of return on common equity reduction for the Uniform Sewer Rate Division. The Commission concludes that if the requested deferral for the WWTP projects is not allowed, it would appear that the Company's already low rate of return on common equity would be further eroded and that the Company would not have a reasonable opportunity to earn its authorized rate of return on common equity.

Furthermore, given the Company's depressed level of current earnings and its expected near-term significant financing needs, the Commission determines that deferral of the WWTP costs as requested by CWSNC will have a favorable impact on CWSNC's earnings and financial standing in general. As such, the deferral will enhance the Company's ability to access and obtain capital on more favorable terms, as it will help assure investor confidence in the Company. Such results will ultimately accrue to the benefit of CWSNC's customers.

Moreover, the Company and the Public Staff have agreed by Stipulation that the Company should be allowed to defer the incremental post-in-service depreciation expense and financing costs of the WWTPs at Nags Head and Connestee Falls as requested by CWSNC because they are both unusual in nature and material to the Company's financial condition. In light of the Commission's having accepted the Stipulation in its entirety and in light of the foregoing independent determination based on the evidence of record that the costs at issue are both unusual, non-routine, and material to the Company's financial well-being, the Commission finds the Company's request to defer post-in-service depreciation and financing costs for the WWTP projects is just and reasonable and should be approved.

Thus, as provided in the Stipulation, Revised Settlement Exhibits I and II, and the testimony of witness Henry (as revised on the stand) and in Henry Late-Filed Exhibits 2, 3, and 4, the Commission finds and concludes that the Company should be authorized to defer its WWTP costs of $1,098,778 related to its WWTPs (consisting of incremental post-in-service depreciation expense and financing costs from their respective in-service dates until the WWTPs are included for recovery in base rates in this case), and these costs should be amortized over five years, for an annual amount to be included in rates of $219,756.

Unlike the deferral accounting request related to the WWTP projects, the Public Staff opposed deferral accounting treatment of the costs associated with the two AMR meter installation projects. The Commission agrees with the Public Staff. The Commission finds that the Company provided insufficient evidence that the projects and their associated costs are unusual or extraordinary such as to warrant deferral accounting. While a mass replacement of meters in an entire subdivision is not an everyday occurrence for CWSNC, the Commission is not convinced that such an event is sufficiently unusual or extraordinary to justify special deferral accounting treatment. The need to replace meters on a planned schedule is an anticipated need of the business and the timing and manner of implementation of such replacement, at least as was the case in this proceeding, is entirely within the control of the Company. Further, the Company did not establish by clear and convincing evidence that the meter installation costs sought to be deferred support a finding that the projects or said costs are unusual or extraordinary. On cross-examination witness DeStefano confirmed that the Company had sought and received rate recovery in its Docket No. W-354, Sub 344 (Sub 344) rate case for AMR meter installation projects that occurred in 2015 in seven systems. The evidence presented confirmed that the Company's Sub 344 rate increase included the costs of 1,157 AMR meters, for a total cost of over $1.2 million, and in the Company's Sub 356 rate case, CWSNC received rate recovery for AMR meter installation projects in three systems, including 2,440 meters, for a total cost of over $1.8 million. Considering that since 2015 CWSNC has completed ten AMR meter projects, including 3,597 meters at a total capital cost of over $3 million, the Commission determines that the two AMR meter installation projects for Fairfield Mountain and Connestee Falls in the amount of $880,209 are not major non-routine, infrequent, non-regularly occurring investments of considerable complexity and significance for CWSNC. Rather, the Commission finds that the two AMR meter installation projects are routine and regularly occurring and are not unusual or extraordinary in nature.

Having determined that the Company failed to establish that its AMR meter installation project and the related costs were unusual or extraordinary such as to justify allowing exceptional deferral accounting treatment, the Commission does not reach the issue of whether the AMR costs sought to be deferred have a material adverse impact on the Company's financial condition or stability. The determination that this project and its related costs are not unusual or extraordinary is dispositive. Therefore, the Company's petition to defer these costs is not just and reasonable and is denied. However, the Commission emphasizes that decisions such as this one are made on a case-by-case basis, and this decision should not be construed to suggest that costs relating to a meter project can never be allowed deferral accounting treatment. The Commission acknowledges that every request for deferral accounting is shaped by its own unique factual circumstances, and whether an event and its related costs are sufficiently unusual or extraordinary in nature to merit an exception to the general rule against deferral accounting treatment is a determination for the Commission that will be based on the specific facts of each such request. The Commission notes that the Company's request for deferral accounting treatment for costs related to the WWTPs and the two AMR installation projects is determined within the context of this general rate case where the Commission is setting just and reasonable rates on a going-forward basis. The Commission's decision either granting or denying deferral accounting treatment in the present case is made from the standpoint of fairness and equity to both consumers and the Company.

Although deferral accounting is to be employed sparingly, the Commission finds that CWSNC has another option available to use to recover costs associated with future AMR meter deployments. Recognizing the challenges confronting North Carolina's water and wastewater industries in needing to make high cost capital investments to install and replace aging infrastructure, the General Assembly has provided the Commission with a tool specific to water and sewer utilities to alleviate the effects of regulatory lag. Section 62-133.12 authorizes the Commission to approve a rate adjustment mechanism in a general rate case to allow a water or sewer utility to recover the incremental depreciation expense and capital costs associated with reasonable and prudently incurred investment in eligible system improvement projects through the collection from customers of a water or sewer system improvement charge (WSIC or SSIC). The Commission approved such a mechanism for CWSNC in Docket No. W-354, Sub 336 pursuant to an order issued on March 10, 2014. Eligible water system improvements to be recovered by use of WSIC include "distribution system mains, valves, utility service lines (including meter boxes and appurtenances), meters, and hydrants installed as in-kind replacements." N.C.G.S. § 62-133.12(c)(1).

Notwithstanding this tool created to help utilities better manage regulatory lag, both Public Staff witness Junis and CWSNC witness DeStefano testified that, other than deferral, there is currently no rate mechanism such as the WSIC or SSIC mechanism available to the Company to mitigate the regulatory lag and resultant adverse earnings impacts associated with the mass replacement of traditional meters with AMR meters because, according to them, the WSIC and SSIC statute only allows recovery for "in-kind" replacements. Tr. vol. 8, 61-62, 195–96. As is clear from the testimony and CWSNC's stated position in its proposed order, the Company has accepted the Public Staff's interpretation that replacing an analog meter with an AMR meter is not an "in-kind" replacement. Tr. vol. 8, 61–62. The Commission does not agree with this interpretation. Although this question has not previously been brought to the Commission for decision, the Commission holds that the exchange of one type of meter reading device for another type of meter reading device is an "in-kind" replacement as that term is used in

N.C.G.S. § 62-133.12(c)(1). The Public Staff appears to read the words "in kind" to mean "like kind and quality' or perhaps "like grade and quality" but this amounts to an impermissible rewriting of the statute. Such an interpretation would defeat the purpose of providing water and sewer utilities with the opportunity to seek recovery under an approved rate adjustment mechanism. Black's Law Dictionary defines "in kind" as "of the same species or category" or "in the same kind, class or genus." Black's Law Dictionary (5th ed. 1979) Bouvier Law Dictionary defines "in kind" as "[p]roperty in its physical form, or property similar to property in issue. In kind refers to specific property, either the property itself in issue or similar property of the same form, quality, and value as the property in issue." Bouvier Law Dictionary (Desk ed. 2020) The Commission concludes an "in-kind" replacement can be an identical replacement or one that is a reasonable alternative to serve the same purpose. If the General Assembly's use of "in kind" limited replacement to the exact identical equipment, upgrade replacements could never be eligible improvements for WSIC or SSIC recovery. A utility seeking to replace a non-functioning obsolete item of equipment with the then-current industry standard equipment would be stymied, and the Commission is not able to conclude that such an outcome was intended by a statute that was meant to facilitate repair and replacement of basic items of utility plant and equipment. Accordingly, with regard to AMR meter installation projects planned for the future, CWSNC and the Public Staff should work together pursuant to Commission Rule R7-39 to mitigate regulatory lag using WSIC recovery. However, the Commission's decision herein does not in any way relieve the Company of its burden to prove its investments are reasonable and prudently incurred as required by N.C.G.S. § 62-133.12 and Commission Rule R7-39(a). Moreover, in its Order Adopting Rules to Implement G.S. § 62-133.12, *Petition for Rulemaking to Implement G.S.62-133.12, North Carolina Session Law 2013-106(House Bill 710)*, No. W-100, Sub 54 (N.C.U.C. June 6, 2014), the Commission concluded that

> any rate adjustments authorized under the WSIC and SSIC mechanisms outside of a general rate case will be allowed to become effective, but not unconditionally approved. In other words, the adjustments will be provisional, will not be deemed *prima facie* just and reasonable, and, thus, may be rescinded retroactively in the utility's subsequent general rate case, at which time the adjustment may be further examined for a determination of its justness and reasonableness.

Id. at 5.

The Commission also notes the Company's testimony and evidence regarding ongoing improvement projects and the need and plans for substantial capital investment in the near future. In consideration of this continuing and anticipated increase in capital spending to address aging infrastructure, the Commission recommends that CWSNC seek to make better use of the WSIC and SSIC mechanisms as a regulatory tool to mitigate the negative effects of regulatory lag for all statutorily allowed system improvement projects.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

Depreciation and Amortization Expense

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Public Staff witnesses Feasel and Henry, and the testimony of Company witness DeStefano. The following table summarizes the differences between the Company's level of depreciation and amortization expenses from its Application and the amounts recommended by the Public Staff:

Item	Company per Application	Difference	Amount per Public Staff
Depreciation expense	$6,399,241	$181,470	$6,580,711
Amortization exp. - CIAC	(1,485,664)	8,710	(1,476,955)
Amortization exp. - PAA	(85,341)	8,718	(76,623)
Amortization of ITC	(579)	0	(579)
Total	$4,827,656	$198,898	$5,026,554

With respect to CWSNC's depreciation expense, in light of the agreements reached in the Stipulation and revisions recommended by the Public Staff in its testimony and reflected in Henry Revised Exhibit I and Feasel Revised Exhibits I and II, the Company does not dispute the adjustments recommended by the Public Staff to depreciation expense. As detailed elsewhere in this Order, the Commission finds that the adjustments recommended by the Public Staff to depreciation expense, which are not contested, are appropriate adjustments to be made to operating revenue deductions in this proceeding.

Based on the foregoing, the Commission concludes that the appropriate level of depreciation and amortization expense for use in this proceeding is as follows:

Item	Amount
Depreciation expense	$6,580,711
Amortization expense – CIAC	(1,476,955)
Amortization expense – PAA	(76,623)
Amortization of ITC	(579)
Total	$5,026,554

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

Franchise, Property, Payroll and Other Taxes

The evidence supporting this finding of fact is found in the verified Application and the accompanying NCUC Form W-1, and in the testimony of Public Staff witness Henry and Company witness DeStefano. The following table summarizes the differences between the Company's level of franchise, property, payroll, and other taxes from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Difference	Amount per Public Staff
Franchise and other taxes	($789)	$135	($655)
Property taxes	268,734	0	268,734
Payroll taxes	596,100	(68,672)	527,428
Total	$864,045	$(68,537)	$795,507

With the Stipulation and revisions made by the Public Staff in its Feasel Revised Exhibits I and II and Henry Revised Exhibit I, the Company does not dispute adjustments recommended by the Public Staff to franchise and other taxes and property taxes. Therefore, the Commission finds that the adjustments recommended by the Public Staff to franchise and other taxes and payroll taxes, which are not contested, are appropriate adjustments to be made to operating revenue deductions in this proceeding.

Based on the foregoing, the Commission concludes that the appropriate level of franchise, property, payroll, and other taxes for use in this proceeding is as follows:

Item	Amount
Franchise and other taxes	($655)
Property tax	268,734
Payroll taxes	527,428
Total	$795,507

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 44-47

Regulatory Fee and Income Taxes

The evidence supporting these findings of fact is found in the testimony of Public Staff witnesses Boswell and Henry, and of Company witness DeStefano. The following table summarizes the differences between the Company's level of regulatory fee and income taxes from its Application and the amounts recommended by the Public Staff:

Item	Company per Application	Difference	Amount per Public Staff
Regulatory fee	$56,361	($12,202)	$44,159
State income taxes	218,982	(143,508)	75,474
Federal income taxes	1,793,462	(1,175,329)	618,133
Deferred income taxes	0	(69,128)	(69,128)
Total	$2,068,805	($1,400,167)	$668,638

Regulatory Fee

The difference in the level of regulatory fee is due to the differing levels of revenues recommended by the Company and the Public Staff. Based on conclusions reached elsewhere in this Order regarding the levels of revenues, the Commission concludes that the appropriate level of regulatory fee for use in this proceeding is $44,159.

State Income Taxes

The difference in the level of state income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in the Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of state income taxes for use in this proceeding is $75,474 based on the current state corporate income tax rate of 2.50%.

Federal Income Taxes

The difference in the level of federal income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in the Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of federal income taxes for use in this proceeding is $618,133 based on the current federal corporate income tax rate of 21.00%.

Deferred Income Taxes

With the Stipulation and revisions made by the Public Staff in its Feasel Revised Exhibits I and II, and Henry Revised Exhibit I, and in the testimony of witness Boswell and Boswell Exhibit 1, the Company agreed with the Public Staff adjustment to deferred income tax of $69,128 to reflect the annual amortization of protected and unprotected federal EDIT.

Based on the foregoing, the Commission concludes that the appropriate level of regulatory fee and income taxes for use in this proceeding is as follows:

Item	Amount
Regulatory fee	$44,159
State income taxes	75,474
Federal income taxes	618,133
Deferred income taxes	(69,128)
Total	$668,638

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 48-50

The Federal Tax Cuts and Jobs Act

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the testimony of Company witness DeStefano, the testimony of Public Staff witness Boswell, and the Stipulation and Settlement Exhibit 1.

In its Application and in the direct testimony of CWSNC witness DeStefano, the Company proposes to include adjustments to the reserve balances for both federal protected EDIT and federal unprotected EDIT based upon the Company's final 2017 federal income tax return filed in late 2018. For federal protected EDIT the Company recommends that the Commission conclude that it is appropriate for CWSNC to continue to return the federal protected EDIT balance maintaining the amortization period approved by the Commission in the Sub 360 Order. In addition, in witness DeStefano's testimony, the Company recommends reducing the term of the federal unprotected EDIT rider approved in the Sub 360 Order (originally 48 months with 35 months now remaining) to a two-year (or 24-month) term as of the effective date of the current proceeding.

Public Staff witness Boswell stated in her direct testimony that certain adjustments to book balances and reserves related to EDIT were recorded to CWSNC's books, adjustments that were not reflected in the Company's most recent rate case. She noted that these adjustments affect the balance of both federal protected EDIT and federal unprotected EDIT. Witness Boswell further stated that the adjustments to the federal protected EDIT and federal unprotected EDIT balances are primarily because: (1) the Company took advantage of a late IRS notice stating that regulated utilities were allowed 100% bonus depreciation for those assets placed in service during the period of September 28, 2017, to December 31, 2017, without a binding contract in place before September 28, 2017, and (2) the Company adjusted amounts utilized in the prior rate case to the actual amounts on its final tax return for 2017. Witness Boswell recommended one adjustment to correct mismatched calculations. She proposed calculating both federal protected EDIT and federal unprotected EDIT amortizations with the adjustments effective as of April 1, 2020. Finally, the Public Staff does not oppose the Company's request to refund the remaining federal unprotected EDIT balance over 24 months instead of the remaining 35 months as originally ordered in Sub 360.

Settlement Exhibit I filed with the Stipulation in the current proceeding reflects the correction to the calculation of federal unprotected EDIT proposed by Public Staff witness Boswell, the reduction of the rider period for the federal unprotected EDIT from 35 months to 24 months, and includes the rate base impact of the flow back of federal protected EDIT in accordance with the RSGM, as approved in Sub 360, in the revenue requirement. In addition, the revenue requirement depicted on Settlement Exhibit I also includes the flow back of state EDIT in accordance with previous Commission orders in Sub 356 and Sub 360. No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that it is reasonable and appropriate for purposes of this proceeding to accept the Stipulation between CWSNC and the Public Staff on the tax issues. Therefore, the Commission concludes that CWSNC should continue to flow back the federal protected EDIT in accordance with the RSGM as ordered in Sub 360, and the Company shall refund its remaining federal unprotected EDIT balances over 24 months instead of the remaining 35 months as originally ordered by the Commission in Sub 360. Further, CWSNC should continue to flow back the state EDIT (which was originally over a three-year period) in accordance with the Commission's Sub 356 Order as confirmed in the Commission's Sub 360 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 51-59

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application and the accompanying NCUC Form W-1, the testimony and exhibits of the public witnesses, the direct and rebuttal testimony and exhibits of Company witness D'Ascendis, and the direct and supplemental testimony and exhibits of Public Staff witness Hinton.

Rate of Return on Equity

The Commission's consideration of the evidence and decision on this issue is set out below and is organized into three sections. The first is a summary of the record evidence on rate of return on common equity. The second is a summary of the law applicable to the Commission's decision on rate of return on common equity. The third is an application of the law to the evidence and a discussion and explanation of the Commission's ultimate decision on rate of return on common equity.

Summary of Record Evidence on Return on Equity

In its Application, the Company requested approval for its rates to be set using a rate of return on common equity of 10.75%. This request was based upon and supported by the direct testimony of CWSNC witness D'Ascendis. In his rebuttal testimony, witness D'Ascendis reduced his recommended rate of return on common equity to 10.20% based upon his updated analyses. This rate of return on common equity compares to a 9.75% rate of return on common equity underlying CWSNC's current rates. Public Staff witness Hinton, in his direct testimony, recommended a rate of return on common equity for CWSNC of 9.00%. In his supplemental testimony, witness Hinton revised and increased his recommended return on common equity to 9.10%.

Direct and Rebuttal Testimony of Dylan W. D'Ascendis (CWSNC)

Company witness D'Ascendis recommended in his direct testimony a rate of return on common equity of 10.75%. This 10.75% was based upon his indicated cost of common equity of 10.35%, plus a recommended size adjustment of 0.40%. In his rebuttal testimony, witness D'Ascendis provided an updated analysis reflecting current investor expectations and reduced his recommended rate of return on common equity to 10.20%, including his recommended 0.40% size adjustment.

CWSNC witness D'Ascendis' recommendation was based upon his Discounted Cash Flow (DCF) model, his Risk Premium Model (RPM), and his Capital Asset Pricing Model (CAPM), applied to market data of a proxy group of six water companies (Utility Proxy Group). He also applied the DCF, RPM, and CAPM to a proxy group of domestic, non-price regulated companies (Non-Price Regulated Proxy Group) which he described as comparable in total risk to his Utility Proxy Group.

The results derived from witness D'Ascendis' analyses in his direct and rebuttal testimony are as follows:

Summary of D'Ascendis Pre-Filed Testimony on Common Equity Cost Rate		
	Direct Testimony	Rebuttal Testimony
Discounted Cash Flow Model	8.70%	8.81%
Risk Premium Model	10.62%	10.12%
Capital Asset Pricing Model	10.21%	9.35%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Proxy Group	11.78%	11.29%
Indicated Common Equity Cost Rate Before Adjustment	10.35%	9.80%
Size Adjustment	0.40%	0.40%
Recommended Common Equity Cost Rate After Adjustment	10.75%	10.20%

He concluded that a common equity cost rate of 9.80% for CWSNC is indicated before any Company-specific adjustments. He then adjusted this indicated rate upward by 0.40% to reflect CWSNC's smaller relative size as compared with the members of his Utility Proxy Group, resulting in a size-adjusted indicated common equity cost rate of 10.20%.

CWSNC witness D'Ascendis testified the six companies in his Utility Proxy Group were: American States Water Co.; American Water Works Co., Inc.; Artesian Resources, Inc.; California Water Service Group; Middlesex Water Co.; and York Water Co.

CWSNC witness D'Ascendis testified he used the single-stage constant growth DCF model. He testified his unadjusted dividend yields are based on the proxy companies' dividends as of October 18, 2019, divided by the average of closing market prices for the 60 trading days ending October 18, 2019.[15] He made an adjustment to the dividend yield because dividends are paid periodically, usually quarterly.

For CWSNC witness D'Ascendis' DCF growth rate he testified he only used analysts' five-year forecasts of earning per share (EPS) growth. He testified the mean result of his application of the single-stage DCF model is 8.73%, the median result is 8.88%, and the average of the two is 8.81% for his Utility Proxy Group as shown on D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 3. He testified in arriving at a conclusion for the DCF-indicated common equity cost rate for his Utility Proxy Group, he relied on an average of the mean and the median results of the DCF.

Witness D'Ascendis used two risk premium methods. He testified his first method is the Predictive Risk Premium Model (PRPM), while the second method is a Risk Premium Model Using an Adjusted Total Market Approach. He testified the PRPM estimates the risk/return relationship directly, as the predicted equity risk premium is generated by the prediction of volatility or risk. He testified the inputs to his PRPM are the historical returns on the common shares of each company in the Utility Proxy Group minus the historical monthly yield on long-term U.S. Treasury securities through April 2019. He testified he added the forecasted 30-year U.S. Treasury Bond yield, 2.64% to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. His rebuttal mean PRPM indicated common equity cost rate for the Utility Proxy Group is 11.30%, and the median is 10.38%. He relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 10.84% as shown on D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 11, column (5).

CWSNC witness D'Ascendis testified his total market approach RPM adds a prospective public utility bond yield to an average of (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, and (2) an equity risk premium based on the S&P Utilities Index. He calculated in his rebuttal testimony the adjusted prospective bond yield for the Utility Proxy Group to be 4.01% as shown on D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 12, line 5, and the average equity risk premium to be 5.38% resulting in risk premium derived common equity to be 9.39% for his RPM using his Total Market Approach.

For his CAPM, witness D'Ascendis testified he applied both the traditional CAPM and the empirical CAPM (ECAPM) to the companies in his Utility Proxy Group and averaged the results. He testified the model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta coefficient. For his CAPM beta coefficient, he considered two methods of calculation: the average of the beta coefficients of the Utility Proxy Group companies reported by Bloomberg

[15] See Schedule DWD-1R, page 3, footnote 1.

Professional Services, and the average of the beta coefficients of the Utility Proxy Group companies as reported by Value Line Investment Survey (Value Line).

CWSNC witness D'Ascendis in his rebuttal testified the risk-free rate adopted for both applications of the CAPM at 2.64%. This risk-free rate of 2.64% is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters beginning with the fourth calendar quarter of 2019 and ending with the first quarter in 2021, and long-term projections for the years 2021 to 2025, and 2026 to 2030. D'Ascendis Rebuttal Exhibit 1, DWD-1R, page 22, column (5), and page 23, column (2).

Witness D'Ascendis testified on rebuttal that the mean result of his CAPM/ECAPM analyses is 9.39%, the median is 9.31%, and the average of the two is 9.35%. Witness D'Ascendis testified that, consistent with his reliance on the average of his mean and median DCF results, the indicated common equity costs rate using the CAPM/ECAPM is 9.35%.

Witness D'Ascendis also selected 11 domestic, non-price regulated companies for his Non-Price Regulated Proxy Group that he believes are comparable in total risk to his Utility Proxy Group. He calculated common equity cost rates using the DCF, RPM, and CAPM for the Non-Price Regulated Proxy Group. In his rebuttal testimony, witness D'Ascendis' DCF result was 11.63%, his RPM cost rate was 11.41%, and his CAPM/ECAPM cost rate was 10.44%. Witness D'Ascendis testified that the average of the mean and median of these models was 11.29%, which he used as the indicated common equity cost rate for the Non-Price Regulated Proxy Group.

Based on the results of the application of multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, witness D'Ascendis testified that the reasonable, appropriate and indicated cost of equity for CWSNC before any adjustment for relative risk was 9.80%.

Witness D'Ascendis also made a 0.40% equity cost rate adjustment due to CWSNC's small size relative to the Utility Proxy Group. He testified that the Company has greater relative risk than the average company in the Utility Proxy Group because of its smaller size compared with the group, as measured by an estimated market capitalization of common equity for CWSNC (whose common stock is not publicly traded). This resulted in a size-adjusted cost of common equity for CWSNC of 10.20%.

Additionally, witness D'Ascendis stated that he had reviewed the Commission's Sub 360 Order regarding the issues of the use of the PRPM, the ECAPM, the use of a non-price regulated proxy group, and the applicability of a size adjusted cost of common equity for CWSNC. In response to these concerns, witness D'Ascendis provided testimony further supporting the inclusion of such factors in determining his recommended return on equity.

Specifically, in terms of the PRPM, he addressed the Commission's concerns about using a specific statistical package to calculate the PRPM results, which made the Commission skeptical that investors would place significant weight on the model. He explained that the general autoregressive conditional heteroskedasticity (GARCH) model used for the PRPM has been in the public domain since the 1980s and is available in several statistical packages which are not financially prohibitive for investors.

In response to the Commission's concerns regarding the ECAPM, which were that there was not enough evidence in the record as to why the ECAPM was superior to the CAPM, witness D'Ascendis provided substantially more information on the subject than what was presented in Sub 360.

In response to the Commission's concerns regarding the use of non-price regulated companies, which were that the non-price regulated companies were not of similar risk to the utility proxy group, witness D'Ascendis provided an additional measure of risk to show that, indeed, his non-price regulated proxy group was similar in total risk to the utility proxy group. The study showed that the non-price regulated proxy group's mean and median coefficient of variation (CoV), of net profit were within the range of CoVs of net profit set by the utility proxy group. The coefficient of variation is often used by investors and economists to determine volatility (i.e. risk) and the use of net profit directly ties to earnings and stock prices.

Finally, witness D'Ascendis responded to the Commission's concerns regarding the size adjustment which were whether the size studies presented in the record were applicable to utilities, and that the selection of a 40-basis point adjustment from an indicated 461 basis point risk premium was rather arbitrary. In order to provide more information to the Commission in this case, witness D'Ascendis conducted a study on whether the size effect is in fact applicable to utilities. His study included the universe of water, gas, and electric companies included in Value Line Standard Edition. From each of the utilities' Value Line Ratings & Reports, witness D'Ascendis calculated the 10-year CoV of net profit (a measure of risk) and current market capitalization (a measure of size) for each company. After ranking the companies by size (largest to smallest) and risk (least risky to most risky), he made a scatter plot of the data, as shown on Chart 1 in his direct testimony.

Witness D'Ascendis testified that, as shown in his Chart 1 of his direct testimony, as company size decreases (increasing size rank), the CoV increases, linking size and risk for utilities. The R-Squared value of 0.0962 means that approximately 10% of the change in risk rank is explained by the size rank. While a 0.0962 R-Squared value does not appear to have strong explanatory power, the average R-Squared value of the Utility Proxy Group's beta coefficient is 0.0794. The selection of a 40-basis point upward adjustment based on its difference in size given an indicated risk premium of approximately 400 basis points is consistent with the approximate 0.10 R-Squared value of the size study applicable to utilities. With this additional information, witness D'Ascendis stated that he hoped the Commission would revisit this concern in its Order in this case.

Witness D'Ascendis' rebuttal testimony criticized the testimony of witness Hinton's approach to estimating CWSNC's required return on equity for a number of perceived shortcomings, including Hinton's:

(a) Inclusion of a gas proxy group to determine a rate of return on common equity for a water utility;
(b) Misapplication of the discounted cash flow model;
(c) Misapplication of the risk premium model;
(d) Misapplication of the capital asset pricing model;
(e) Misapplication of the Comparable Earnings Model;
(f) Failure to account for size-specific risks; and
(g) Opinion that the approval of the Company's requested consumption adjustment mechanism (CAM) in this proceeding requires a downward adjustment to the rate of return on common equity.

Tr. vol. 8, 267–68.

CWSNC Witness D'Ascendis Cross-Examination

CWSNC witness D'Ascendis testified on cross-examination that in the Middlesex Water Company, New Jersey general rate case decided in July 2015, he recommended a specific rate of return on common equity of 10.40%, but that a rate of return on common equity of 9.75% was approved which was 65 basis points less than his recommendation. Witness D'Ascendis testified that in the Carolina Water Service, Inc. South Carolina 2015 general rate case where his recommended rate of return on common equity range was 10.00% to 10.50%, the approved rate of return on common equity was 9.34% which was 91 basis points below the midpoint of his recommended range.

CWSNC witness D'Ascendis further testified on cross-examination that in the Middlesex Water Company, New Jersey general rate case decided in March 2018, his recommended specific rate of return on common equity was 10.70%, and a 9.60% rate of return on common equity was approved whereby his recommended rate of return on common equity was 110 basis points above the approved rate of return on common equity. He testified that the 2018 South Carolina decision for Carolina Water Service, Inc. of South Carolina was the only one of the fifteen listed return on equity decisions, that a commission approved an allowed rate of return on common equity within his recommended range. He also testified that in the recent CWSNC general rate case, order dated February 21, 2019, his recommended rate of return on common equity range was 10.80% to 11.20%, with a midpoint of 11.00%, which was 125 basis points above the Commission approved rate of return on common equity of 9.75%.

Witness D'Ascendis testified on cross-examination that the authorized rates of return on equity for all 15 decisions averaged 127 basis points below his recommended rates of return on equity, and after removing a 2016 outlier case in Missouri where he was 360 basis points above the approved rate of return on common equity, the average difference between falls to 110 basis points. He further testified on cross-examination that his rebuttal specific return on equity recommendation of 10.20% less the 110 basis points, would be the same number as Public Staff witness Hinton's recommended 9.10% rate of return on common equity.

Witness D'Ascendis also testified that Public Staff D'Ascendis Cross-Examination Exhibit 1, page 2 listed the RRA approved rates of return on equity for the last three years for his Utility Proxy Group companies with approved average rates of return on equity of 9.42%.

Witness D'Ascendis testified that as shown on Public Staff D'Ascendis Cross-Examination Exhibit 2, which was a RRA summary of commission approved rates of return on equity from January 2014 through June 30, 2019, the average approved return on equity was 9.50% for 30 return on equity decisions in the most recent three-year period July 1, 2016 through June 30, 2019.

With respect to his recommended 40 basis point size adjustment, witness D'Ascendis testified on cross-examination that he knew CWSNC served approximately 50,000 customers in North Carolina, was the second largest Commission regulated water and wastewater utility in North Carolina, and the two next largest companies serve approximately 7,000 customers each.

Witness D'Ascendis testified he was aware CWSNC did not have any industrial customers, and that more than 99.5% of its customers were residential plus some small stores and some schools. He testified that CWSNC was geographically diversified in North Carolina with systems along the North Carolina coast, the Piedmont and throughout the mountains.

Witness D'Ascendis further testified on cross-examination that CWSNC obtains all its debt through its parent, Utilities, Inc., and that CWSNC does not go into the debt market. He testified that Utilities Inc. is owned by Corix. Witness D'Ascendis read into the record sections of the pre-filed testimony of Corix CEO and President Gordan Barefoot, which stated Corix provides to CWSNC a full suite of support services, and Corix provides access to favorable terms for debt financing in capital markets. Both the Public Staff and CWSNC used the Utilities, Inc. capital structure and debt costs for CWSNC in this general rate case.

Witness D'Ascendis testified that based on Public Staff D'Ascendis Cross-Examination, Exhibit 4, that the Utilities, Inc. has common equity of $280.2 million. When multiplied by the D'Ascendis Utility Proxy Group market to book ratio of 347.3%, the result is a market capitalization for Utilities, Inc. of $973.3 million. Witness D'Ascendis testified that this market capitalization of three of the companies in the D'Ascendis Utility Proxy Group; those companies being Artesian Resources Corporation at $316.0 million, York Water Company at $440.0 million, and Middlesex Water Company at $951.0 million.

CWSNC witness D'Ascendis on cross-examination further testified Public Staff D'Ascendis Cross-Examination Exhibit 5 was a comparison of the growth in dividends and stock market prices of the D'Ascendis Proxy Group of companies from April 15, 2011 to November 29, 2019. During that period dividend and stock price movements were as follows:

Company	Dividend Growth	Share Price Appreciation
American States Water	126%	378%
American Water Works	127%	419%
Artesian Resource Group	32%	91%
California Water Service	27%	173%
Middlesex Water Company	29%	243%
York Water Co.	36%	163%
Six Company Average	59%	245%

Witness D'Ascendis testified that he agreed that stock market prices have increased materially since April 2011, and dividend amounts have lagged way behind. He further testified that dividend yields are one of the two major components of the DCF.

During cross-examination CWSNC witness D'Ascendis also testified as to the stock price increases subsequent to the California Public Utilities Commission Order dated March 22, 2018 which approved a 9.20% rate of return on common equity for California American Water Co., a wholly-owned subsidiary of American Water Works; a 9.20% rate of return on common equity for California Water Service Co.; an 8.90% rate of return on common equity for Golden State Water Co., a wholly-owned subsidiary of American States Water; and an 8.90% rate of return on common equity for San Jose Water Co. The stock market percentage increases for the period March 22, 2018 to November 29, 2019, were: American Water Works 51.0%, American States Water 56.6%, California Water Service 36.3% and San Jose Water 33.1%, as shown on Public Staff D'Ascendis Cross-Examination Exhibit 6.

Witness D'Ascendis also testified on cross-examination about the significant decrease in the yields of 30-year Treasury Bond and A-Rated Public Utility Bonds as shown on Public Staff D'Ascendis Cross-Examination Exhibit 7. During the one-year period September 2018 to September 2019, the yields on A Rated Public Utility Bonds decreased from 4.32% to 3.37%, a decrease of 95 basis points from the previous CWSNC general rate case expert witness hearing heard before the Commission on October 16, 2018. Witness D'Ascendis' risk free 30-year Treasury Bond projected yield in this current case, shown in rebuttal exhibits filed on November 20, 2019, Schedule DWD-1R, page 22 was 2.64% compared to the 3.74% in September 2018, as stated in his prior Sub 360 CWSNC case testimony in D'Ascendis Rebuttal Exhibit 1, Schedule DWD-1R, page 11, column 6, and page 22, footnote 2, resulting in a bond yield decrease between his two rebuttal testimonies of 110 basis points. He further testified that as of November 29, 2019, the actual 30-year Treasury Bond yield was 2.19% compared to the October 16, 2018 actual 30-year Treasury Bond yield of 3.32%, a decrease of 113 basis points.

With respect to the non-price regulated companies in witness D'Ascendis' testimony for which he performed DCF, Risk Premium and CAPM analyses, he testified on cross-examination that these companies had competition unlike CWSNC, which has franchises protecting it from competition by other investor owned water utilities. Witness D'Ascendis testified that each time he has presented the non-priced regulated company analyses, the Commission has rejected and given no weight to these analyses.

Witness D'Ascendis testified that the Commission in CWSNC's February 19, 2019, Sub 360 Order found credible, probative, and entitled to substantial weight to his DCF, Total Market Risk Premium, and Traditional CAPM. He testified that his rebuttal exhibits in this case for these same analyses stated DCF 8.81%, Total Market Risk Premium 9.39%, Traditional CAPM 8.90%, with the average of these three of his models being 9.03%, all as shown on Public Staff D'Ascendis Cross-Examination Exhibit 10.

In response to a request by Chair Mitchell, CWSNC witness D'Ascendis filed a Late Filed Exhibit on December 13, 2019, showing the effect on each of his models using witness Hinton's 2.53% interest rate as the current yield for 30-year Treasury Bonds rather than the projected yields in witness D'Ascendis' rebuttal exhibits. This D'Ascendis On-the-Record Data Request provided the following results:

	D'Ascendis Late-Filed Exhibit #1
Discounted Cash Flow Model	8.81%
Risk Premium Model	10.00%
Capital Asset Pricing Model	9.29%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Proxy Group	11.16%
Indicated Common Equity Cost Rate Before Adjustment	9.75%
Size Adjustment	0.40%
Recommended Common Equity Cost Rate After Adjustment	10.15%

Public Staff Witness Hinton Testimony

Public Staff Director of Economic Research John R. Hinton testified the Public Staff recommends an overall rate of return of 7.20%, based on a capital structure consisting of 50.90% long-term debt at a cost rate of 5.36% and 49.10% common equity at a cost rate of 9.10%. He testified his recommendations result in pre-tax interest coverage equaling 3.1 times and a funds flow to debt ratio of 25.0%, which should qualify for a single "A" bond rating.

Witness Hinton described the current financial market conditions, testifying that the cost of financing is much lower today than in the more inflationary period of the 1990s. More recently, the continued low rates of inflation and expectations of future low inflation rates have contributed to even lower long-term interest rates. He testified that according to Moody's Bond Survey, yields on long-term "A" rated public utility bonds have fallen 88 basis points from 4.25% on February 21, 2019, the date of the order in Sub 360, as compared to 3.37% for September 2019. He testified that by the close of this proceeding, CWSNC will have received five rate increases over the last six years in Docket Nos. W-354, Sub 360, Sub 356, Sub 344, and Sub 336. He further testified relative to the filing of the cost of capital settlement in the CWSNC January 2014 rate case in Docket No. W-354, Sub 336, yields on Moody's A-rated utility bonds are 126 basis points lower than the average 4.63% yield observed during the CWSNC January 2014, as illustrated by Hinton Exhibit JRH-1.

Witness Hinton testified that interest rates on various loans have fallen as the yields on treasury securities have declined since the Commission issued its order on February 21, 2019. The graph on page 15 of witness Hinton's direct testimony shows the lower yields that on average are over 100 basis points lower for all durations except for a minor increase in 90-day treasury bills. He testified that the average decrease in treasury bonds of 5-, 7-, 10-, 20-, and 30-year bonds is 111 basis points. He testified while Utilities, Inc., Corix, and its ultimate parent, the British Columbia Investment Management Corporation (BCIMC) generally cannot obtain capital at these interest rates, the falling yields are indicators of the declining cost of debt capital.

Public Staff witness Hinton testified that the current lower interest rates, especially for longer-term securities, and stable inflationary environment of today indicate that borrowers are paying less for the time value of money. He testified that this is significant since utility stocks and utility capital costs are highly interest rate-sensitive relative to most industries within the securities markets. He testified that given that investors often view purchases of the common stocks of utilities as substitutes for fixed income investments, the reductions in interest rates observed over the past ten years or more has paralleled the decreases in investor required rates of return on common equity.

Public Staff witness Hinton testified that he does not rely on interest rate forecasts. Rather, he believes that relying on current interest rates, especially in relation to yields on long-term bonds, is more appropriate for ratemaking in that it is reasonable to expect that as investors in the marketplace price bonds based upon expectations on demand and supply of capital, future interest rates, inflation rates, etc. He testified that while he has a healthy respect for forecasting, he is aware of the risk of relying on predictions of rising interest rates to determine utility rates. He presented a portion of the testimony of Aqua North Carolina, Inc. witness Pauline Ahern in the 2013 Aqua rate case, Docket No. W-218, Sub 363. In that case she identified several interest rate forecasts by Blue Chip Financial Forecasts of 30-year Treasury Bond yields that were predicted to rise to 4.3% in 2015, 4.70% in 2016, 5.20% in 2017, and 5.50% for 2020-2024. He presented the graph 30-Year US Treasury Bonds on page 18 of his direct testimony, which showed in 2015, the range was approximately 2.50% to 3.10%, in 2016 the range was approximately 2.50% to 3.10%, and in 2017 the range was approximately 2.25% to 3.10%. Witness Hinton testified that similar overestimated forecasts can be identified in witness D'Ascendis' Exhibit DWD-4 in the CWSNC's 2018 rate case where the Blue-Chip consensus forecast predicted the 30-year Treasury Bonds would rise to 3.80% by the third quarter of 2019. According to the Federal Reserve, the highest observed yield on 30-year Treasury Bonds for the third quarter of 2019 is 2.65%, and the average for the quarter was 2.29%. He testified that these types of errors make these interest rate forecasts inappropriate for ratemaking.

Public Staff witness Hinton testified that he used the discounted cash flow (DCF) model and the Risk Premium model to determine the cost of equity for CWSNC. He testified that the DCF model is a method of evaluating the expected cash flows from an investment by giving appropriate consideration to the time value of money. Witness Hinton testified that the DCF model is based on the theory that the price of the investment will equal the discounted cash flows of returns. The return to an equity investor comes in the form of expected future dividends and price appreciation. He testified that as the new price will again be the sum of the discounted cash flows, price appreciation is ignored, and attention focused on the expected stream of dividends.

Witness Hinton testified that he applied the DCF method to a comparable group of seven water utilities followed by Value Line Investment Survey. He testified that the standard edition of Value Line covers eight water companies. He excluded Consolidated Water Co. due to its significant overseas operations. Witness Hinton included a group of nine natural gas local distribution companies (LDCs) in his DCF analysis stating these LDCs exhibit risk measures similar to his proxy group of water companies.

Public Staff witness Hinton calculated the dividend yield component of the DCF by using the Value Line estimate of dividends to be declared over the next 12 months divided by the price of the stock as reported in the Value Line Summary and Index sections for each week of the 13-week period July 26, 2019, through October 18, 2019. He testified that a 13-week averaging period tends to smooth out short-term variations in the stock prices. This process resulted in an average dividend yield of 1.7% for his proxy group of water utilities and 2.6% for the LDC group utilities.

To calculate the expected growth rate component of the DCF, Public Staff witness Hinton employed the growth rates of his proxy group in earnings per share (EPS), dividends per share (DPS), and book value per share (BPS) as reported in Value Line over the past ten and five years. He also employed the forecasts of the growth rates of his water and LDC proxy groups in EPS, DPS, and BPS as reported in Value Line. He testified that the historical and forecast growth rates are prepared by analysts of an independent advisory service that is widely available to investors and should also provide an estimate of investor expectations. He testified that he includes both historical known growth rates and forecast growth rates, because it is reasonable to expect that investors consider both sets of data in deriving their expectations.

Public Staff witness Hinton testified that he also incorporated the consensus of various analysts' forecasts of five-year EPS growth rate projections as reported in Yahoo Finance. He testified the dividend yields and growth rates for each of the companies and for the average for his comparable proxy groups are shown in Exhibit JRH-4.

Public Staff witness Hinton concluded that based upon his DCF analysis that a reasonable expected dividend yield is 1.7% with an expected growth rate of 6.0% to 7.0%. He testified that his DCF analysis produces a cost of common equity for his comparable proxy group of water utilities of 7.7% to 8.7%. Based upon the DCF analysis for the comparable group of LDCs, he determined that a reasonable expected dividend yield is 2.6%, with an expected growth rate of 5.7% to 6.7%, which yields a range of results of 8.3% to 9.3% for the cost of equity.

He testified that his ultimate DCF based cost of equity is based on the average estimates for the two groups of companies, which he summarized in his Hinton Exhibit 8 that quantifies an approximate range of DCF based cost of equity estimates of 8.48% to 8.80% for his DCF based cost of equity estimate of 8.64%.

Witness Hinton testified that the equity risk premium method can be defined as the difference between the expected return on a common stock and the expected return on a debt security. The differential between the two rates of return are indicative of the return investors require in order to compensate them for the additional risk involved with an investment in the company's common stock over an investment in the company's bonds that involves less risk.

Witness Hinton testified that his method relies on approved returns on common equity for water utility companies from various public utilities commissions that is published by the Regulatory Research Associates, Inc. (RRA), within SNL Global Market Intelligence. In order to estimate the relationship with a representative cost of debt capital, he regressed the average annual allowed equity returns with the average Moody's A-rated yields for Public Utility Bonds from 2006 through 2019. His regression analysis which incorporates years of historical data is combined with recent monthly yields to provide an estimate of the current cost of common equity.

Witness Hinton testified that the use of allowed returns as the basis for the expected equity return has two strengths over other approaches that involve various models that estimate the expected equity return on common stocks and subtracting a representative cost of debt. He testified that one strength of his approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. He testified that it is reasonable to conclude that the approved allowed returns are good estimates of the cost of equity.

Public Staff witness Hinton testified that the summary data of risk premiums shown on his Exhibit JRH-5, page 1 of 2, indicates that the average risk premium is 5.00%, with a maximum premium of 5.78%, and minimum premium of 3.73%, which when combined with the last six months of Moody's A-rated utility bond yields produces yields with an average cost of equity of 8.70%, a maximum cost of equity of 9.48%, and a minimum cost of equity of 7.44%. To better estimate the current cost of equity, he performed a statistical regression analysis as shown on Exhibit JRH 5, page 2 of 2 in order to quantify the relationship of allowed equity returns and bond costs. He testified that by applying the risk premium to the current utility bond cost of 3.71%, resulted in a current estimate of the equity risk premium of equity of 9.57%.

Public Staff witness Hinton concluded that based on all of the results of his DCF model that indicate a cost of equity from 8.48% to 8.80% with a central point estimate of 8.64%, and the risk premium model that indicates a cost of equity of 9.57%, he determined that the investor required rate of return on common equity for CWSNC is between 9.11% which he rounded to 9.10% as shown on Hinton Exhibit 8.

Public Staff witness Hinton testified as to the reasonableness of his recommended return, that he considered the pre-tax interest coverage ratio produced by his cost estimates for the cost equity. He testified that based on his recommended capital structure, cost of debt, and equity return of 9.10%, the pre-tax interest coverage ratio is approximately 3.1 times. He testified that this tax interest coverage and a funds flow to debt ratio of 25.0%, as shown on Supplemental Hinton Exhibit 10, should allow CWSNC to qualify for a single “A” bond rating.

Witness Hinton also performed a comparable earnings analysis and a CAPM analysis solely as checks on the results of this DCF and Risk Premium Regression Analysis. He testified that his comparable earnings analysis for a group of eight water utilities and nine LDC companies produced a five-year average return on equity of 9.83%. He testified that a weakness is that actual earned rates of return can be impacted by factors outside the company’s control, such as weather, inflation, and tax changes, including deferred income taxes. These unforeseen developments can cause a company’s earned rate of return to exceed or fall short of its cost of capital during any certain period making this method somewhat less reliable than other cost of capital methods, and it suffers from circular reasoning. In addition, he testified that earned rates of return on equity may often include non–regulated income. He testified that his CAPM analysis utilizing his preferred geometric mean return produced return on equity estimates of 7.65% and 7.68% that are at the low end of CWSNC’s cost of equity. As such, he testified his CAPM provides a limited check on his recommended cost of equity.

Witness Hinton in his direct testimony had a recommended a rate of return on common equity of 9.10% with a downward 10 basis point adjustment to reflect reduced risk due to the consumption adjustment mechanism CWSNC applied for in this proceeding. His resulting recommended allowed rate return on equity was thus 9.00%. After CWSNC withdrew its request for a consumption adjustment mechanism, witness Hinton filed supplemental testimony withdrawing this 10-basis point downward adjustment.

Witness Hinton testified that his recommended return on common equity takes into consideration the impact of the water and sewer system improvement charges (WSIC and SSIC) pursuant to N.C.G.S. § 62-113.12 on CWSNC’s financial risk. He testified that the WSIC and SSIC mechanisms provide the ability for enhanced cost recovery of the eligible capital improvements which reduces regulatory lag through incremental and timely rate increases. He testified he believes this mechanism is seen by debt and equity investors as supportive regulation that mitigates business and regulatory risk. Witness Hinton testified that he believes that this mechanism is noteworthy and is supportive of his 9.10% return on equity recommendation.

Witness Hinton testified that it is not appropriate to add a risk premium to the cost of equity due to the size of the company. He testified that CWSNC is owned by Corix Infrastructure, Inc. (Corix), which is owned by BCIMC. Corix has a significant influence over the balances of common equity and long-term debt of Utilities, Inc. and CWSNC. Corix determines the amounts of dividend payments to BCIMC and the frequency of those payments. He testified that from a regulatory policy perspective; ratepayers should not be required to pay higher rates because they are located in the franchise area of a utility of a size which is arbitrarily considered to be small. He further testified that if such adjustments were routinely allowed, an incentive would exist for large existing utilities to form subsidiaries when merging or even to split-up into subsidiaries as to obtain higher allowed returns. He further testified that CWSNC operates in a franchise environment that insulates the company from competition and it operates with procedures in place that allow for rate adjustments for eligible capital improvements, cost increases, and other unusual circumstances that impact its earnings. Witness Hinton testified that CWSNC operates in the water and sewer industry, where expensive bottled water provides the only alternative to utility service. It is factually correct that rating agencies and investors add a risk factor for small companies with relatively limited capital resources; however, the inherent protection from competition removes this risk that would otherwise be a concern to investors.

Witness Hinton noted that he also testified to these same size adjustment concerns in the last CWSNC rate case, Sub 360, where the Commission found that a size adjustment was not warranted. He testified that similar arguments were made in a 1997 CWS System, Inc., rate case, Docket No. W-778, Sub 31, by witness Hanley of AUS Consultants, who relied on similar cost of capital methods as witness D'Ascendis, as noted on pages 824-25 in its Eighty-Seventh Report of Orders and Decisions. In CWSNC's 1994 rate case, Docket No. W-354, Sub 128, the Commission was not persuaded to accept an adjustment for small size and its elevated risk, as noted on page 520 in its Eighty-Fourth Report on Orders and Decisions. Tr. vol. 7, 785–86. In a rate case brought by North Carolina Natural Gas, Inc., Docket No, G-21, Sub 293, the explicit consideration of the small size of a regulated utility was argued before this Commission. In its December 6, 1991 Order in that case, the Commission disagreed with the Company witness who testified that the Company's small size warranted the selection of other small sized companies in his proxy group. Witness Hinton testified that while there are published studies that address how the small size of a company relates to higher risks, he is aware of only one study by Dr. Annie Wong[16] that focuses on the size of regulated utilities and risk. He testified that Dr. Wong has tested the data for a size premium in utilities and concluded that "unlike industrial stocks, utility stocks do not exhibit a significant size premium. As explained, there are several reasons why such a size

[16] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," Journal of the Midwest Finance Association, pp. 95-101, (1993).

premium would not be attributable to utilities because they are regulated closely by state and federal agencies and commissions, and hence, their financial performance is monitored on an ongoing basis by both the state and federal governments." Tr. vol. 7, 187.

Public Staff Witness Hinton Cross-Examination

Witness Hinton testified on cross-examination that the electric and natural gas industries in North Carolina have a number of surcharge rate adjustment mechanisms available to them which serve to enhance revenue recovery and thereby stabilize earnings and that those mechanisms also employ deferral accounting as part of the true-up process. Witness Hinton also testified that all utilities are concerned with regulatory lag and that surcharge rate adjustment mechanisms reduce regulatory lag, . . . maybe significantly . . . ." Tr. vol. 7, 105, 93.

Witness Hinton also testified on cross-examination that during "the last couple years your [CWSNC's] earned returns have been less than your allowed returns." *Id.* at 104.

Witness Hinton further stated that he considered his initial proposal (which he withdrew when CWSNC withdrew its request to implement a CAM) to impose a 10-basis point downward adjustment with respect to his recommended rate of return on common equity in consideration of the Company's initially-proposed CAM to be a "material" adjustment. *Id.* at 111.

Witness Hinton also testified on cross-examination that the 23-basis point reduction in CWSNC's cost of long-term debt from 5.59% at the time the Company filed its Verified Rate Case Application to 5.36% at September 30, 2019, was "material." *Id*. at 133.

Law Governing the Commission's Decision on Return on Equity

In the absence of a settlement agreed to by all parties the Commission must exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including the rate of return on common equity. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d 707. In order to reach an appropriate independent conclusion regarding the rate of return on common equity the Commission should evaluate the admitted 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 evidence relating to the Company's cost of equity capital was presented by Company witness D'Ascendis and Public Staff witness Hinton. No rate of return on common equity expert evidence was presented by any other party.

The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & 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*) which, as the Commission has previously noted, establish that:

> 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.

DEC Sub 1146 Order at 50; *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The rate of return on common equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital.

> [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* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] 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.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *Public Staff,* 323 NC at 490, 374 S.E.2d at 369. Likewise, the Commission has observed as much in exercising its duty to determine the rate of return on common equity, noting that such determination is not made by application of any one simple mathematical formula:

> 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. 381-82. (notes omitted)

Order Granting General Rate Increase, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd, State ex rel. Utils. Comm'n v. Cooper,* 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order) (additions and omissions after the first quoted paragraph in original).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but, as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *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, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates, and adjusted for proven changes occurring up to the close of the evidentiary hearing) is but one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. *See* N.C.G.S. § 62-133. North Carolina General Statute § 62-133(b)(4) provides in pertinent part that the Commission shall:

> Fix such rate of return on the cost of the property . . .as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on common equity-related factors—the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Case Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the testimony of expert witnesses regarding their analyses of the rate of return on common equity using various economic models widely used and accepted in utility regulatory rate-setting proceedings. 2013 DEP Rate Case Order, at 38. Further,

> [t]he 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 . . . .

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates, but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return, just as the Commission is constrained to address the impact of difficult economic times on customers' ability to pay for service by establishing a lower rate of return on common equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise is constrained to address the effect of regulatory lag[17] on the Company by establishing a higher rate of return on common equity in isolation. Instead, the Commission sets the rate of return considering both of these negative impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide reliable electric service and recover its cost of providing service. The Commission is guided by this premise when it makes it determination of the appropriate rate of return on common equity.

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

[17] Regulatory lag exists where a utility's realized, earned return is less than its authorized return negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

Discussion and Application of Law to the Facts in this Case Regarding the Issue of Rate of Return on Common Equity

The Commission has carefully evaluated the testimony of CWSNC witness D'Ascendis and Public Staff witness Hinton. The results of each of the models or methods used by these two witnesses to derive the return on equity that each witness recommends is shown below:

Utility Proxy Group	D'Ascendis Rebuttal Exhibits	D'Ascendis Late-Filed Exhibits	Hinton
DCF	8.81%	8.81%	8.64%
Risk Premium	10.12%	10.00%	9.57%
PRPM	10.84%	10.73%	
Total Market RPM	9.39%	9.27%	
CAPM	9.35%	9.29%	7.65-8.96%*
Traditional CAPM	8.90%	8.84%	
ECAPM	9.80%	9.74%	
Comparable Earnings	———	———	9.83%*
Non–Price Regulated Proxy Group	11.29%	11.16%	———
DCF	11.63%	11.63%	
Risk Premium	11.41%	11.23%	
CAPM	10.44%	10.39%	
Indicated on Return on Equity Before Adjustment	9.80%	9.75%	9.10%
Size Adjustment	0.40%	0.40%	———
Recommended Return on Equity	10.20%	10.15%	9.10%
* Note: Provided solely as a check and not used in formulating this witness's recommended allowed rate of return on common equity.			

The range of the rate of return on common equity recommendations from the two expert witnesses is 9.10% to 10.20%. Underlying the lower rate of return on common equity recommendation of 9.10%, is a rate of return on common equity range of 7.65% to 9.83%, according to witness Hinton's testimony concerning his cost of common equity analyses. Similarly, underlying the higher rate of return on common equity recommendation of 10.20% is a range of 8.81% to 11.29%, according to witness D'Ascendis' rebuttal testimony concerning his cost of common equity analyses. Such a wide range of estimates by expert witnesses is not atypical in proceedings before the Commission with respect to the return on the equity issue. Neither is the seemingly endless debate and habitual differences in judgment among expert witnesses on the virtues of one model or method versus another and how to best determine and measure the required inputs of each model in representing the interests of the party on whose behalf they are testifying. Nonetheless, the Commission is uniquely situated, qualified, and required to use its impartial judgment to determine the return on equity based on the testimony and evidence in this proceeding in accordance with the legal guidelines discussed above.

In doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness Hinton, are credible, probative, and are entitled to substantial weight as set forth below. The Commission further finds that the rate of return on common equity trends, particularly as embodied by data points in Public Staff D'Ascendis Cross-Examination Exhibits 1 and 2 to be credible, positive and corroborative evidence entitled to some weight.[18] Accordingly, the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support and corroboration to a finding that a 9.50% rate of return on common equity is appropriate in this case.

Company witness D'Ascendis, noting that CWSNC is not publicly traded, first established a group of six relatively comparable risk water companies that are publicly traded (Utility Proxy Group). He testified that use of relatively comparable risk companies as proxies is consistent with principles of fair rate of return established in the Hope and Bluefield cases, which are recognized as the primary standards for the establishment of a fair return for a regulated public utility. He then applied the DCF, the CAPM, and the risk premium models to the market data of the Utility Proxy Group. Witness D'Ascendis' DCF model indicated a cost of equity of 8.81%, his CAPM model indicated a cost of equity of 9.29%, and his Risk Premium model indicated a cost of equity of 10.00%. The Commission finds and concludes that analyses using interest rate forecasts rely unnecessarily on projections. The Commission approves the use of current interest rates, rather than projected near–term or long–term interest rates. The Commission finds witness D'Ascendis' late-filed exhibit Risk Premium Model and his late-filed exhibit CAPM analysis using the current 30–year Treasury yields to be credible, probative and entitled to substantial weight.

Witness Hinton applied a risk premium analysis by performing a regression analysis using the allowed returns on common equity for water utilities from various public utility commissions, as reported in an RRA Water Advisory, with the average Moody's

[18] The Commission determines the appropriate rate of return on common equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on common equity trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on common equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on common equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary. In this proceeding, witness Hinton's risk premium analysis, as well as Public Staff D'Ascendis Cross-Examination Exhibit No. 1, page 2 and No. 2 provide credible, positive and corroborative evidence.

A-rated bond yields for public utility bonds from 2006 through 2019. The results of the regression analysis were combined with recent monthly yields to provide the current cost of equity. According to witness Hinton, the use of allowed returns as the basis for the expected equity return has strengths over other risk premium approaches that estimate the expected return on equity and subtract a representative cost of debt. He testified that one strength of his approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. Thus, it is reasonable to conclude that the approved returns are good estimates for the cost of equity. Witness Hinton testified that applying the significant statistical relationship of the allowed equity returns and bond yields from the regression analysis and adding current utility bond cost of 3.71% resulted in a current estimate of the cost of equity of 9.57%.

The average of witness D'Ascendis' Utility Proxy Group late-filed exhibit DCF result of 8.81%, CAPM result of 9.29% and RPM result of 10.00% and witness Hinton's RPM of 9.57% is 9.42%. A return on common equity of 9.50% is thus supported by the average of the results of the four above-listed cost of equity models which the Commission finds are credible, probative, and entitled to consideration based on the record in this proceeding.

The Commission gives no weight to the DCF, CAPM and comparable earnings analyses of witness Hinton who presented his CAPM and comparable earnings methods only as a check on his DCF and Risk Premium Regression analyses. For reasons generally stated by witness D'Ascendis, the Commission concludes that witness Hinton's use of a proxy group of natural gas companies in his DCF and CAPM analyses is inappropriate for determining the appropriate return on equity in this case. The indicated returns on equity using the water proxy groups in witness Hinton's DCF (8.48%) and CAPM (7.65% to 8.96% with a midpoint of 8.31%) are outliers as they fall far below the other rate of return on common equity analyses in this proceeding.

Witness Hinton's comparable earnings analyses are not reliable as the earned rates of return on equity listed in Hinton Exhibit 6 contain non-regulated earnings and increased earnings resulting from deferred income taxes. Witness D'Ascendis on cross-examination testified that American States Water has significant operations in Army bases around the country and also has an electric utility. Although the California Utilities Commission on March 22, 2018, approved an 8.90% rate of return on common equity for Golden State Water Company which is a wholly-owned subsidiary of American States Water as shown on Public Staff D'Ascendis Cross-Examination Exhibit 6, American States Water achieved earned rates of return on equity of 11.40% in 2018 and 12.0% in 2019 as shown on Hinton Exhibit 6. In addition, although the most recent rate order for Middlesex Water Co. in New Jersey was issued on March 24, 2018, which approved a 9.60% rate of return on common equity as shown on Public Staff D'Ascendis Cross-Examination Exhibit 3, the Middlesex Water Co. earned rate of return on common equity for 2018 was 13.0% and 2019 earned rate of return on common equity was 12.0% as shown on Hinton Exhibit 6.

In addition to estimating the cost of equity for his Utility Proxy Group of publicly-traded water utilities, witness D'Ascendis attempted to estimate the cost of equity for another proxy group consisting of 10 domestic, non-price regulated companies. The rebuttal results of the DCF, RPM, and CAPM applied to the non-price regulated proxy group are 11.63%, 11.23%, and 10.39%, respectively. The Commission concludes that these results are unreasonably high. Each of these results is higher than witness D'Ascendis' estimates of the cost of equity for his own Utility Proxy Group and deserves no weight. The Commission further concludes that given the difference in these results, the risk of the two groups is not equal and the Utility Proxy Group is more reliable as a proxy for the investment risk of common equity in CWSNC.

After determining that the indicated cost of equity from the DCF, CAPM, and risk premium methods applied to both of his proxy groups equals in his rebuttal 9.80% rate of return on common equity, witness D'Ascendis then adjusted the indicated cost of equity upward by 0.40% to reflect CWSNC's smaller size compared to companies in his Utility Proxy Group. He testified that the size of the company is a significant element of business risk for which investors expect to be compensated through higher returns. Witness D'Ascendis calculated his size adjustment as described in his prefiled direct testimony and stated that even though a 3.94% upward size adjustment is indicated, he applies a 0.40% size premium to CWSNC's indicated common equity cost rate.

Witness Hinton testified that he does not believe it is appropriate to add a risk premium to the cost of equity of CWSNC due to size for several reasons. First, from a regulatory policy perspective, witness Hinton stated that ratepayers should not be required to pay higher rates because they are located in the franchise area of a utility that is arbitrarily considered to be small. Further, if such adjustments were routinely allowed, an incentive would exist for large utilities to form subsidiaries or split-up subsidiaries to obtain higher returns. In addition, he noted that CWSNC operates in a franchise environment that insulates the Company from the competition with procedures in place for rate adjustments for circumstances that impact its earnings. Finally, while witness Hinton stated that while there are studies that address how the small size of a company relates to higher returns, he is aware of only one study that focuses on the size of regulated utilities and risk and that study concluded that utility stocks do not exhibit a significant differential in risk due to size. In rebuttal, witness D'Ascendis maintained that a small size adjustment was necessary based on the results of studies he cited and discussed. He contended that the study concerning size premiums for utilities discussed by witness Hinton was flawed.

The uncontroverted evidence is that both CWSNC and the Public Staff used the Utilities, Inc. capital structure and debt cost in this proceeding. CWSNC obtains all its debt and equity from CWSNC's parent company Utilities, Inc. CWSNC does not participate in the debt markets. The Corix CEO, Gordon Barefoot, testified that Corix, the parent company of Utilities, Inc., provides access to favorable terms for debt financing in capital markets.

Based upon the foregoing and the entire record in this proceeding, the Commission concludes that a size adjustment of 0.40% is not warranted and should not be approved. The Commission determines there is insufficient evidence to authorize an adjustment to the approved rate of return on common equity in this case. The record simply does not indicate the extent to which CWSNC's size alone justifies the added risk premium. While a small water/wastewater utility might face greater risk than a publicly-traded peer group, because for example the service area was confined to a hurricane-prone coastal geographic area, evidence of such factual predicates is absent from the record. CWSNC has water and wastewater systems along the North Carolina coast, in the Piedmont, and in the mountains. The Commission notes that the witnesses also disagreed with respect to whether the studies discussed in the testimony concerning size and risk are reliable or even applicable to regulated utilities. The Commission concludes that the testimony regarding these studies is not convincing and does not support a size adjustment.

Having determined that the appropriate rate of return on common equity based upon the evidence in this proceeding is 9.50%, the Commission notes that there is considerable testimony concerning the authorized returns on equity for water utilities in other jurisdictions. While the Commission has relied upon the record in this proceeding and is certainly aware that returns in other jurisdictions can be influenced by many factors, such as different capital market conditions during different periods of time, settlements versus full litigation, the Commission concludes that the rate of return on common equity trends and decisions by other regulatory authorities deserve some weight as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return significantly higher than other utilities of comparable risk would result in customers paying more than necessary.

Public Staff D'Ascendis Cross-Examination Exhibit 2, which has RRA approved rate of return on common equity listings showing approved return on equity decisions for water utilities across the country from January 2014 through June 30, 2019, is helpful in illustrating that the average rate of return on common equity for water utilities was 9.59% in 2014, 9.79% in 2015, 9.71% in 2016, 9.31% in 2017, 9.45% in 2018, and in the only five reported cases for the first six months of 2019 the average is 9.60%. This authorized return data is generally supportive of the Commission approved return on equity of 9.50% based upon all the evidence in this proceeding.

These factors lead the Commission to conclude that a 9.50% rate of return on common equity is supported by the substantial weight of the evidence in this proceeding. However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers.

In this case all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D'Ascendis and Hinton, which the Commission finds entitled to substantial weight, addresses changing economic conditions. As to the impact of changing economic conditions on CWSNC's customers, witness Hinton testified that he reviewed information on the economic conditions in the areas served by CWSNC, specifically, the 2016 and 2017 data on total personal income from the Bureau of Economic Analysis (BEA) and the 2019 Development Tier Designations published by the North Carolina Department of Commerce for the counties in which CWSNC's systems are located. The BEA data indicates that total personal income weighted by the number of water customers by county grew at a compound annual growth rate of approximately 3.1%.

Witness Hinton testified that the North Carolina Department of Commerce annually ranks the state's 100 counties based on economic well-being and assigns each a Tier designation. The most distressed counties are rated a "1" and the most prosperous counties are rated a "3". The rankings examine several economic measures such as, household income, poverty rates, unemployment rates, population growth, and per capita property tax base. For 2017, the average Tier ranking that has been weighted by the number of water customers by county is 2.5. He testified that both of these economic measures indicate that there has been improvement in the economic conditions for CWSNC's service area relative to the three previous CWSNC rate increases in Sub 360, Sub 356, and Sub 344 that were approved in 2019, 2017, and 2015, respectively.

Witness D'Ascendis testified concerning his review of economic conditions in North Carolina that he reviewed. He testified that he reviewed: unemployment rates from the United States, North Carolina, and the counties comprising CWSNC's service territory; the growth in Gross National Product (GDP) in both the United States and North Carolina; median household income in the United States and in North Carolina; and national income and consumption trends.

Witness D'Ascendis testified that the rate of unemployment has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00% and 12.00%, respectively. He testified that by April 2019, the unemployment rate had fallen to less than one-half of those peak levels: 3.30% nationally; and 3.60% in North Carolina.

Witness D'Ascendis testified that he was also able to review (seasonally unadjusted) unemployment rates in the counties served by CWSNC. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached an average 12.86% (58 basis points higher than the State-wide average); by April 2019, it had fallen to 3.68% (8 basis points higher than the state-wide average).

Witness D'Ascendis testified that for real Gross Domestic Product growth, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 69%). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina's rate of growth. He testified that since the second quarter of 2015; however, North Carolina has consistently exceeded the national growth rate.

As to median household income, witness D'Ascendis testified that the correlation between North Carolina and the U.S. is relatively strong (approximately 87% from 2005 through 2018). Since 2009, the years subsequent to the financial crisis, median household income in North Carolina has grown at a similar annual rate as the national median income (2.32% vs. 2.65%).

Witness D'Ascendis summarized stating in the Commission's order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the cost of common equity. He testified that those relationships still hold: Economic conditions in North Carolina continue to improve from the recession following the 2008/2009 financial crisis, and they continue to be strongly correlated to conditions in the United States, generally. He testified that unemployment, at both the State and county level, continues to fall and remains highly correlated with national rates of unemployment; real Gross Domestic Product recently has grown faster in North Carolina than the national rate of growth, although the two remain fairly well correlated; and median household income also has grown faster in North Carolina than the rest of the Country, and remains strongly correlated with national levels.

The Commission's review also includes consideration of the evidence presented by 23 witnesses during the public witness hearings, almost all of whom presently are customers of CWSNC. The Commission held six evening hearings throughout CWSNC's North Carolina service territory to receive public testimony. The testimony presented at the hearings illustrates the difficult economic conditions facing many North Carolina citizens. The Commission accepts as credible, probative, and entitled to substantial weight the testimony of the public witnesses.

Based upon the general state of the economy and the continuing affordability of water and wastewater utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that an allowed rate of return on common equity of 9.50% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from this decision. When the Commission's decisions are viewed as a whole, including the decision to establish the rate of return on common equity at 9.50%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.[19]

All of the scores of adjustments the Commission approves reduce the revenues to be recovered from ratepayers and the return to be paid to equity investors. Some

[19] The Commission notes consumers pay rates, a charge in dollars per 1,000 gallons for the water they consume and a monthly flat rate for residential wastewater customers. They do not pay a "rate of return on equity," though it is a component of the Company's cost of providing service which is built into the billed rates. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.50%.

adjustments reduce the authorized rate of return on investment financed by equity investors. The noted adjustments are made solely to reduce rates and provide rate stability to consumers (and return to equity investors) to recognize the difficulty for consumers to pay in the current economic environment. while the equity investor's cost was calculated by resort to a rate of return on common equity of 9.50% instead of the 10.20% recommended by CWSNC witness D'Ascendis on rebuttal. This is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of these other adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.

Despite the improving economic conditions and their effects on CWSNC's customers, the Commission recognizes the financial difficulty that an increase in CWSNC's rates may create for some of CWSNC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on CWSNC's customers in reaching its decision regarding CWSNC's approved rate of return on common equity.

The Commission recognizes that the Company is investing significant sums in system improvements to serve its customers, thus requiring the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on CWSNC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable water and wastewater service. Safe, adequate, and reliable water and wastewater service is essential to the well-being of CWSNC's customers.

The Commission finds and concludes that these investments by the Company provide significant benefits to CWSNC's customers. The Commission concludes that the return on equity approved by the Commission in this proceeding appropriately balances the benefits received by CWSNC's customers from CWSNC's provision of safe, adequate, and reliable water and wastewater service with the difficulties that some of CWSNC's customers will experience in paying CWSNC's increased rates.

The Commission notes further that its approval of a rate of return on common equity at the level of 9.50% or for that matter at any level, is not a guarantee to the Company that it will earn a rate of return on common equity at that level. Rather, as North Carolina law requires, setting the rate of return on common equity at this level merely affords CWSNC the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the rate of return on common equity provided for herein will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are just and reasonable to its customers.

Capital Structure

CWSNC witness D'Ascendis' direct testimony recommended the use of the actual capital structure of Utilities, Inc. of 52.04% long-term debt and 47.96% common equity as of March 31, 2019.

In his testimony Public Staff witness Hinton recommended a 50.90% long-term debt and 49.10% common equity capital structure based upon updated information provided by CWSNC concerning the Utilities, Inc. actual capital structure at September 30, 2019. The Partial Stipulation also supports a 50.90% long-term debt and 49.10% common equity capital structure. No other party presented evidence as to a different capital structure.

Accordingly, the Commission finds that the recommended capital structure of 49.10% common equity and 50.90% long-term debt is just and reasonable to all parties in light of all the evidence presented.

Cost of Debt

In its Application CWSNC proposed a cost rate for long-term debt of 5.59%. In his testimony, witness Hinton recommended the cost of debt 5.36% as of September 30, 2019. In addition, the Stipulation includes a cost of debt rate of 5.36%. No other party offered any evidence supporting a debt cost rate below 5.36%.

Therefore, the Commission finds that the use of a debt cost rate of 5.36% is just and reasonable to all parties based upon the evidence presented in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60

Revenue Requirement

The following schedules summarize the gross revenue and overall rate of return that the Company should have a reasonable opportunity to achieve based on the increases in revenues approved in this Order for each rate entity. These schedules, illustrating the Company's gross revenue requirements, incorporate the adjustments found appropriate by the Commission in this Order.

SCHEDULE I

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
CWSNC Combined Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$33,852,232	$4,969,441	$38,821,673
Miscellaneous revenues	387,492	14,956	402,448
Uncollectibles	(271,142)	(38,638)	(309,780)
Total operating revenues	33,968,582	4,945,759	38,914,341
Operating Revenue Deductions:			
Salaries and wages – Maintenance	4,949,710	0	4,949,710
Purchased power	2,103,043	0	2,103,043
Purchased water and sewer	2,219,243	0	2,219,243
Maintenance and repair	3,120,935	0	3,120,935
Maintenance testing	544,432	0	544,432
Meter reading	206,176	0	206,176
Chemicals	693,596	0	693,596
Transportation	534,200	0	534,200
Operating expense charged to plant	(665,133)	0	(665,133)
Outside services – other	1,191,299	0	1,191,299
Salaries and wages – General	2,004,409	0	2,004,409
Office supplies & other office exp.	568,864	0	568,864
Regulatory commission expense	307,754	0	307,754
Pension and other benefits	1,600,158	0	1,600,158
Rent	330,308	0	330,308
Insurance	782,562	0	782,562
Office utilities	747,670	0	747,670
Miscellaneous	218,417	0	218,417
Depreciation expense	6,580,711	0	6,580,711
Amortization of CIAC	(1,476,955)	0	(1,476,955)
Amortization of PAA	(76,623)	0	(76,623)
Amortization of ITC	(579)	0	(579)
Franchise and other taxes	(655)	0	(655)
Property taxes	268,734	0	268,734
Payroll taxes	527,428	0	527,428
Regulatory fee	44,159	6,429	50,588
Deferred income tax	(69,128)	0	(69,128)
State income tax	75,474	123,484	198,958
Federal income tax	618,133	1,011,327	1,629,460
Rounding	0	1	1
Total operating revenue deductions	27,948,343	1,141,241	29,089,584
Net operating income for a return	$6,020,239	$3,804,518	$9,824,757

SCHEDULE II

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
CWSNC Combined Operations

Item	Amount
Plant in service	$238,212,084
Accumulated depreciation	(57,897,943)
Net plant in service	180,314,141
Cash working capital	2,404,800
Contributions in aid of construction	(40,270,675)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(5,995,444)
Customer deposits	(315,447)
Inventory	271,956
Gain on sale and flow back taxes	(417,811)
Plant acquisition adjustment	(837,878)
Excess book value	0
Cost-free capital	(261,499)
Average tax accruals	(143,198)
Regulatory liability for excess deferred taxes	(3,941,344)
Deferred charges	2,122,707
Pro forma plant	0
Original cost rate base	$132,897,368
Rates of return:	
Present	4.53%
Approved	7.39%

SCHEDULE III

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
CWSNC Combined Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.90%	$ 67,644,760	5.36%	$3,625,759
Common Equity	49.10%	65,252,608	3.67%	2,394,480
Total	100.00%	$132,897,368		$6,020,239
		APPROVED RATES		
Long-Term Debt	50.90%	$ 67,644,760	5.36%	$3,625,759
Common Equity	49.10%	65,252,608	9.50%	6,198,998
Total	100.00%	$132,897,368		$9,824,757

SCHEDULE I-A

Carolina Water Service, Inc. of North Carolina

Docket No. W-354, Sub 364

Net Operating Income for a Return

For the Twelve Months Ended March 31, 2019

CWSNC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$17,485,912	$1,785,873	$19,271,785
Miscellaneous revenues	189,818	5,357	195,175
Uncollectibles	(129,396)	(13,215)	(142,611)
Total operating revenues	17,546,334	1,778,015	19,324,349
Operating Revenue Deductions:			
Salaries and wages – Maintenance	2,684,228	0	2,684,228
Purchased power	1,048,858	0	1,048,858
Purchased water and sewer	1,478,502	0	1,478,502
Maintenance and repair	909,143	0	909,143
Maintenance testing	202,228	0	202,228
Meter reading	175,422	0	175,422
Chemicals	311,580	0	311,580
Transportation	283,615	0	283,615
Operating expense charged to plant	(360,703)	0	(360,703)
Outside services – other	654,506	0	654,506
Salaries and wages – General	1,086,991	0	1,086,991
Office supplies & other office expense	308,786	0	308,786
Regulatory commission expense	169,355	0	169,355
Pension and other benefits	867,766	0	867,766
Rent	178,706	0	178,706
Insurance	423,389	0	423,389
Office utilities	411,346	0	411,346
Miscellaneous	120,273	0	120,273
Depreciation expense	3,198,990	0	3,198,990
Amortization of CIAC	(704,302)	0	(704,302)
Amortization of PAA	(115,669)	0	(115,669)
Amortization of ITC	(328)	0	(328)
Franchise and other taxes	(3,473)	0	(3,473)
Property taxes	154,066	0	154,066
Payroll taxes	286,024	0	286,024
Regulatory fee	22,810	2,312	25,122
Deferred income tax	(26,513)	0	(26,513)
State income tax	50,650	44,393	95,043
Federal income tax	414,823	363,575	778,398
Total operating revenue deductions	14,231,071	410,280	14,641,351
Net operating income for a return	$3,315,263	$1,367,735	$4,682,998

SCHEDULE II-A
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
CWSNC Water Operations

Item	Amount
Plant in service	$114,766,817
Accumulated depreciation	(29,553,703)
Net plant in service	85,213,114
Cash working capital	1,184,436
Contributions in aid of construction	(17,662,813)
Advances in aid of construction	(23,760)
Accumulated deferred income taxes	(2,312,807)
Customer deposits	(175,942)
Inventory	167,608
Gain on sale and flow back taxes	(281,868)
Plant acquisition adjustment	(2,085,004)
Excess book value	0
Cost-free capital	(121,791)
Average tax accruals	(81,595)
Regulatory liability for excess deferred taxes	(2,084,991)
Deferred charges	1,611,323
Pro forma plant	0
Original cost rate base	$63,345,909

Rates of return:

Present	5.23%
Approved	7.39%

SCHEDULE III-A

Carolina Water Service, Inc. of North Carolina

Docket No. W-354, Sub 364

Statement of Capitalization and Related Costs

For the Twelve Months Ended March 31, 2019

CWSNC Water Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$32,243,068	5.36%	$1,728,228
Common Equity	49.10%	31,102,841	5.10%	1,587,035
Total	100.00%	$ 63,345,909		$3,315,263
		APPROVED RATES		
Long-term Debt	50.90%	$ 32,243,068	5.36%	$1,728,228
Common Equity	49.10%	31,102,841	9.50%	2,954,770
Total	100.00%	$ 63,345,909		$4,682,998

SCHEDULE I-B
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
CWSNC Sewer Operations

	Present Rates	Increase Approved	After Approved Increased
Operating Revenues:			
Service revenues	$12,961,929	$2,942,923	$15,904,852
Miscellaneous revenues	124,500	8,829	133,329
Uncollectibles	(98,511)	(22,366)	(120,877)
Total operating revenues	12,987,918	2,929,386	15,917,304
Operating Revenue Deductions:			
Salaries and wages – Maintenance	1,622,020	0	1,622,020
Purchased power	838,308	0	838,308
Purchased water and sewer	740,741	0	740,741
Maintenance and repair	1,940,932	0	1,940,932
Maintenance testing	308,671	0	308,671
Meter reading	0	0	0
Chemicals	318,617	0	318,617
Transportation	171,371	0	171,371
Operating expense charged to plant	(217,966)	0	(217,966)
Outside services – other	395,475	0	395,475
Salaries and wages – General	656,845	0	656,845
Office supplies & other office exp.	186,580	0	186,580
Regulatory commission expense	102,331	0	102,331
Pension and other benefits	524,372	0	524,372
Rent	107,979	0	107,979
Insurance	255,830	0	255,830
Office utilities	248,550	0	248,550
Miscellaneous	74,254	0	74,254
Depreciation expense	2,821,151	0	2,821,151
Amortization of CIAC	(570,054)	0	(570,054)
Amortization of PAA	(16,931)	0	(16,931)
Amortization of ITC	(251)	0	(251)
Franchise and other taxes	(2,595)	0	(2,595)
Property taxes	93,092	0	93,092
Payroll taxes	172,838	0	172,838
Regulatory fee	16,884	3,808	20,692
Deferred income tax	(33,406)	0	(33,406)
State income tax	14,845	73,140	87,985
Federal income tax	121,581	599,012	720,593
Total operating revenue deductions	10,892,064	675,960	11,568,024
Net operating income for a return	$2,095,854	$2,253,426	$4,349,280

SCHEDULE II-B

Carolina Water Service, Inc. of North Carolina

Docket No. W-354, Sub 364

Original Cost Rate Base

For the Twelve Months Ended March 31, 2019

CWSNC Sewer Operations

Item	Amount
Plant in service	$102,974,564
Accumulated depreciation	(23,646,093)
Net plant in service	79,328,471
Cash working capital	941,771
Contributions in aid of construction	(17,559,280)
Advances in aid of construction	(9,180)
Accumulated deferred income taxes	(2,884,203)
Customer deposits	(106,311)
Inventory	101,275
Gain on sale and flow back taxes	(135,943)
Plant acquisition adjustment	296,963
Excess book value	0
Cost-free capital	(139,708)
Average tax accruals	(49,923)
Regulatory liability for excess deferred taxes	(1,259,826)
Deferred charges	307,657
Pro forma plant	0
Original cost rate base	$58,831,763

Rates of return:

Present	3.56%
Approved	7.39%

SCHEDULE III-B

Carolina Water Service, Inc. of North Carolina

Docket No. W-354, Sub 364

Statement of Capitalization and Related Costs

For the Twelve Months Ended March 31, 2019

CWSNC Sewer Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$ 29,945,367	5.36%	$1,605,072
Common Equity	49.10%	28,886,396	1.70%	490,782
Total	100.00%	$ 58,831,763		$2,095,854
		APPROVED RATES		
Long-term Debt	50.90%	$ 29,945,367	5.36%	$1,605,072
Common Equity	49.10%	28,886,396	9.50%	2,744,208
Total	100.00%	$ 58,831,763		$4,349,280

SCHEDULE I-C
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
BF/FH/TC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$1,304,521	$97,488	$1,402,009
Miscellaneous revenues	51,060	312	51,372
Uncollectibles	(16,567)	(1,239)	(17,806)
Total operating revenues	1,339,014	96,561	1,435,575
Operating Revenue Deductions:			
Salaries and wages – Maintenance	308,862	0	308,862
Purchased power	69,724	0	69,724
Purchased water and sewer	0	0	0
Maintenance and repair	63,151	0	63,151
Maintenance testing	8,314	0	8,314
Meter reading	30,753	0	30,753
Chemicals	44,189	0	44,189
Transportation	38,746	0	38,746
Operating expense charged to plant	(41,503)	0	(41,503)
Outside services – other	69,135	0	69,135
Salaries and wages – General	125,075	0	125,075
Office supplies & other office exp.	35,984	0	35,984
Regulatory commission expense	17,639	0	17,639
Pension and other benefits	99,850	0	99,850
Rent	21,337	0	21,337
Insurance	50,550	0	50,550
Office utilities	43,252	0	43,252
Miscellaneous	11,671	0	11,671
Depreciation expense	169,164	0	169,164
Amortization of CIAC	(56,417)	0	(56,417)
Amortization of PAA	13,303	0	13,303
Amortization of ITC	0	0	0
Franchise and other taxes	2,583	0	2,583
Property taxes	10,553	0	10,553
Payroll taxes	32,912	0	32,912
Regulatory fee	1,741	125	1,866
Deferred income tax	(923)	0	(923)
State income tax	2,145	2,411	4,556
Federal income tax	17,569	19,745	37,314
Total operating revenue deductions	1,189,358	22,281	1,211,639
Net operating income for a return	$149,656	$74,280	$223,936

SCHEDULE II-C
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
BF/FH/TC Water Operations

Item	Amount
Plant in service	$6,285,688
Accumulated depreciation	(2,083,262)
Net plant in service	4,202,426
Cash working capital	124,591
Contributions in aid of construction	(1,055,139)
Advances in aid of construction	0
Accumulated deferred income taxes	(84,226)
Customer deposits	(16,236)
Inventory	1,503
Gain on sale and flow back taxes	0
Plant acquisition adjustment	13,196
Excess book value	0
Cost-free capital	0
Average tax accruals	(5,624)
Regulatory liability for excess deferred taxes	(291,777)
Deferred charges	140,413
Pro forma plant	0
Original cost rate base	$3,029,127
Rates of return:	
Present	4.94%
Approved	7.39%

SCHEDULE III-C
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
BF/FH/TC Water Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$ 1,541,826	5.36%	$82,642
Common Equity	49.10%	1,487,301	4.51%	67,014
Total	100.00%	$ 3,029,127		$149,656
		APPROVED RATES		
Long-term Debt	50.90%	$ 1,541,826	5.36%	$82,642
Common Equity	49.10%	1,487,301	9.50%	141,294
Total	100.00%	$ 3,029,127		$223,936

SCHEDULE I-D
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Net Operating Income for a Return
For the Twelve Months Ended March 31, 2019
BF/FH Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$2,099,870	$143,157	$2,243,027
Miscellaneous revenues	22,114	458	22,572
Uncollectibles	(26,668)	(1,818)	(28,486)
Total operating revenues	2,095,316	141,797	2,237,113
Operating Revenue Deductions:			
Salaries and wages – Maintenance	334,600	0	334,600
Purchased power	146,154	0	146,154
Purchased water and sewer	0	0	0
Maintenance and repair	207,709	0	207,709
Maintenance testing	25,219	0	25,219
Meter reading	0	0	0
Chemicals	19,210	0	19,210
Transportation	40,468	0	40,468
Operating expense charged to plant	(44,961)	0	(44,961)
Outside services – other	72,182	0	72,182
Salaries and wages – General	135,498	0	135,498
Office supplies & other office expense	37,514	0	37,514
Regulatory commission expense	18,429	0	18,429
Pension and other benefits	108,171	0	108,171
Rent	22,286	0	22,286
Insurance	52,793	0	52,793
Office utilities	44,523	0	44,523
Miscellaneous	12,219	0	12,219
Depreciation expense	391,406	0	391,406
Amortization of CIAC	(146,182)	0	(146,182)
Amortization of PAA	42,674	0	42,674
Amortization of ITC	0	0	0
Franchise and other taxes	2,830	0	2,830
Property taxes	11,022	0	11,022
Payroll taxes	35,654	0	35,654
Regulatory fee	2,724	184	2,908
Deferred income tax	(8,286)	0	(8,286)
State income tax	7,834	3,540	11,374
Federal income tax	64,160	28,995	93,155
Total operating revenue deductions	1,635,850	32,719	1,668,569
Net operating income for a return	$459,466	$109,078	$568,544

SCHEDULE II-D
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Original Cost Rate Base
For the Twelve Months Ended March 31, 2019
BF/FH Sewer Operations

Item	Amount
Plant in service	$14,185,016
Accumulated depreciation	(2,614,885)
Net plant in service	11,570,131
Cash working capital	154,002
Contributions in aid of construction	(3,993,443)
Advances in aid of construction	0
Accumulated deferred income taxes	(714,208)
Customer deposits	(16,958)
Inventory	1,570
Gain on sale and flow back taxes	0
Plant acquisition adjustment	936,967
Excess book value	0
Cost-free capital	0
Average tax accruals	(6,056)
Regulatory liability for excess deferred taxes	(304,750)
Deferred charges	63,314
Pro forma plant	0
Original cost rate base	$7,690,568
Rates of return:	
Present	5.97%
Approved	7.39%

SCHEDULE III-D
Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 364
Statement of Capitalization and Related Costs
For the Twelve Months Ended March 31, 2019
BF/FH Sewer Operations

	Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		PRESENT RATES		
Long-term Debt	50.90%	$ 3,914,499	5.36%	$209,817
Common Equity	49.10%	3,776,069	6.61%	249,649
Total	100.00%	$ 7,690,568		$ 459,466
		APPROVED RATES		
Long-term Debt	50.90%	$ 3,914,499	5.36%	$ 209,817
Common Equity	49.10%	3,776,069	9.50%	358,727
Total	100.00%	$ 7,690,568		$ 568,544

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61–63

Rate Design

The evidence supporting these findings of fact is found in the verified Application and the accompanying NCUC Form W-1, the Stipulation, and the testimony and exhibits of Public Staff witnesses Junis and Casselberry and CWSNC witness DeStefano.

The water rates proposed by CWSNC in its Application were based on a fixed-to-variable ratio of 52% fixed for the base facility charge and 48% variable for the usage charge. Sewer rates were based on a fixed-to-variable ratio of 80% fixed for the base facility charge and 20% variable for the usage charge.

As part of its Application and as a matter of rate design in this case CWSNC proposes to include in its Uniform Sewer Rate Division, customers in the CLMS service area. CWSNC has maintained the CLMS system rates steady for the last four general rate cases (Docket No. W-354, Subs 336, 344, 356, and 360) in order to allow the remainder of the Uniform Sewer Rate Division to move toward parity with the CLMS sewer rates.

Public Staff witness Junis testified that the Public Staff recommended a service revenue ratio of 45/55 (base facilities charge to usage charge) for Uniform Water and BF/FH/TC Water residential customers, which he stated was consistent with the Public Staff's previous recommendations in CWSNC rate cases and similar to the stated target of 40/60 in the most recent Aqua North Carolina, Inc. (Aqua) rate case, Docket No. W-218, Sub 497. Moreover, he stated the rate design ratio of 45/55 was incorporated in Public Staff witness Casselberry's testimony and exhibits detailing the billing analysis and proposed rates. Tr. vol. 8, 107, 155.

Public Staff witness Junis recommended a 65/35 ratio for Uniform Sewer residential customers, an incremental approach to the target of 45/55, which was also incorporated in witness Casselberry's billing analysis and proposed rates. Tr. vol. 8, 159. Further, the Public Staff recommended that CLMS should be fully incorporated into the Uniform Sewer Rate Division as requested by the Company and that the Public Staff's recommended rates for the Uniform Sewer Rate Division should apply to CLMS customers.

On December 2, 2019, the CLCA filed a Resolution with the Commission whereby it stated that the Association

- strongly opposes being singled out for higher rates than any other territory served by CWSNC, and requests that the Commission adopt a uniform rate schedule for all CWSNC wastewater treatment customers; and
- requests that the Commission move Corolla Light and Monteray Shores area to the uniform rate schedule after thoroughly investigating and

analyzing the basis of the CWSNC request, allowing only an increase that is clearly justified.

During the expert witness hearing in response to a question from the Commission, CLCA indicated that it has no objection to the Stipulation. Tr. vol. 9, 200–01.

In the Stipulation, the Stipulating Parties agreed to a rate design for water utility service for its Uniform Water and BF/FH/TC Water residential customers to be based on a 50/50 ratio of base charge to usage charge, and to use an 80/20 ratio of base charge to usage charge for CWSNC's Uniform Sewer residential customers.[20]

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to utilize a 50/50 ratio of base charge to usage charge in this proceeding for CWSNC's Uniform Water and BF/FH/TC Water residential customers and an 80/20 ratio of base charge to usage charge for CWSNC's Uniform Sewer residential customers as agreed to by the Company and the Public Staff, embodied in the Stipulation, and not opposed by any party. Further, the Commission concludes that it is reasonable and appropriate to consolidate the CLMS sewer service rates with the Company's Uniform Sewer Division rates as requested by CWSNC and supported by both the Public Staff and the CLCA. The Commission concludes that such rate design is fair and reasonable to both CWSNC and its customers. Therefore, taking into account the forgoing findings and conclusions, the Commission concludes that the rates and charges included in Appendices A-1 and A-2, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto as Appendices B-1 and B-2, are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 64-65

Water and Sewer System Improvement Charges

The evidence supporting these findings of fact is found in the generic rulemaking proceeding, Docket No. W-100, Sub 54, wherein the Commission issued orders establishing procedures for implementing and applying the WSIC and SSIC mechanism; in CWSNC's 2013 rate case, Docket No. W-354, Sub 336, wherein the Commission initially approved the Company's WSIC and SSIC mechanism; and in the Commission's prior orders approving WSIC and SSIC mechanisms for CWSNC and the other Corix companies that have been merged into CWSNC.

The Commission's previously-approved WSIC and SSIC rate adjustment mechanism continues in effect, although as required by Commission Rules R7-39(k) and R10-26(k), it has been reset to zero in this rate case. The WSIC and SSIC mechanism is designed to recover between rate case proceedings the costs associated with investment in certain completed, eligible projects for water and sewer system or water quality improvements pursuant to N.C.G.S. § 62-133.12. The WSIC and SSIC surcharge is

[20] BF/FH Sewer Rate Division has a monthly flat rate for residential customers.

subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC and SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this rate case proceeding.

Based on the service revenues set forth and approved in this Order, the maximum WSIC and SSIC charges as of the effective date of this Order are:

Item	Service Revenues	Cap %	WSIC & SSIC Cap
CWSNC Uniform Water Operations	$19,271,785	X 5% =	$963,589
CWSNC Uniform Sewer Operations	$15,904,852	X 5% =	$795,243
BF/FH/TC Water Operations	$1,402,009	X 5% =	$70,100
BF/FH Sewer Operations	$2,243,027	X 5% =	$112,151

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 66-68

Recommendations of the Public Staff

The evidence for these findings of fact is found in the Company's NCUC Form W-1, the testimony of Public Staff witness Casselberry, and the testimony of Company witness DeStefano.

In her prefiled testimony, witness Casselberry stated,

> The Public Staff recommends that in the next general rate case, W-1, Item 26, be reconciled with the Company's bill data to ensure that the filing does not include double bills, that the Company accounts for multi-unit customers, and that other bills produced, such as final bills, late notices, re-bills, or other miscellaneous bills are not included in the W-1, Item 26 filing.

Tr. vol. 8, 91. The Company does not oppose this recommendation of the Public Staff.

In response to the Commission's question during the expert witness hearing regarding whether the Company will be able to provide the information requested by the Public Staff, witness DeStefano responded that, "[t]he Company expects to be able to provide the information requested." Tr. vol. 9, 197.

In its Application the Company requested to increase its reconnection fee from $27.00 to $42.00. Witness Casselberry stated in her testimony that the Public Staff did not oppose increasing the reconnection fee from $27.00 to $42.00.

In its Application the Company also proposed to increase the water connection charge from $500 to $1,080 and the sewer connection charge from $2,000 to $2,635 for Winston Pointe Subdivision, Phase IA. Witness Casselberry stated in her testimony that the Public Staff recommended a connection charge of $1,080 for water and $1,400 for sewer in Winston Pointe Subdivision, Phase IA, as the connection charge should reflect Johnston County's – where the Company purchases bulk water and sewer treatment for Winston Pointe Subdivision – current bulk capacity fee for water and sewer. Witness Casselberry stated that CWSNC indicated that it agreed with the Public Staff's recommendation. Tr. vol. 8, 94.

In light of the foregoing the Commission concludes that it is reasonable and appropriate for the Company to provide accurate bill data and ensure that accurate data is filed in its NCUC Form W-1, Item 26 in its next rate case filing. The Commission further concludes that the reconnection fee should be increased from $27.00 to $42.00, and that a connection charge of $1,080 for water and $1,400 for sewer in Winston Pointe Subdivision, Phase 1A, is reasonable and appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That the affidavit of CWSNC's Financial Planning and Analysis Manager, Matthew Schellinger, filed on January 10, 2020, and the Public Staff's Revised Settlement Exhibits I and II filed on January 13, 2020, in these dockets are hereby entered into evidence;

2. That all late-filed exhibits filed by CWSNC and the Public Staff in these dockets are hereby admitted into evidence. That the Resolution of Corolla Light Community Association, Inc., filed on December 2, 2019 is also admitted into evidence;

3. That the Partial Joint Settlement Agreement and Stipulation is incorporated herein by reference and is hereby approved in its entirety;

4. That the Partial Joint Settlement Agreement and Stipulation and the parts of this Order pertaining to the contents of that agreement shall not be cited or treated as precedent in future proceedings;

5. That CWSNC's request to defer incremental O&M costs related to Hurricane Florence storm impacts is approved as set forth in the Stipulation and stated herein, and that CWSNC's request to defer depreciation expense on its capital investments and lost revenues related to Hurricane Florence storm impacts is hereby denied;

6. That CWSNC's Petition to defer post-in-service costs associated with the two WWTPs is approved; provided, however, that the Company shall be, and hereby is, required to cease deferring said costs concurrent with the date the Company is authorized to begin reflecting the costs associated with the WWTPs in rates;

7. That CWSNC's Petition to defer post-in-service costs associated with the two AMR installation projects is denied;

8. That the Schedules of Rates, attached hereto as Appendices A-1 and A-2, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto as Appendices B-1 and B-2, are hereby approved and deemed to be filed with the Commission pursuant to N.C.G.S. § 62-138, and are hereby authorized to become effective for service rendered on and after the issuance date of this Order;[21]

9. That the Notices to Customers, attached hereto as Appendices C-1 and C-2 shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process;

10. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than ten days after the Notices to Customers are mailed or hand delivered to customers;

11. That CWSNC's federal protected EDIT should continue to be flowed back in accordance with the RSGM pursuant to the Commission's Sub 360 Order;

12. That it is reasonable and appropriate for purposes of this proceeding for CWSNC to refund its remaining federal unprotected EDIT balances over 24 months instead of the remaining 35 months as originally ordered by the Commission in Sub 360;

13. That CWSNC's state EDIT recorded pursuant to the Commission's Sub 138 Order should continue to be amortized in accordance with the Commission's Sub 356 Order and as confirmed by the Commission in its Sub 360 Order;

14. That CWSNC shall receive estimates for the cost of a filtration system in Bradfield Farms Subdivision within 60 days of the date of this Order and shall share those estimates with the Bradfield Farms Homeowners Association;

15. That with respect to AMR meter installation projects planned for the future, CWSNC shall work with the Public Staff pursuant to N.C.G.S. § 62-133.12 and Commission Rule R7-39 to mitigate regulatory lag using WSIC recovery. The burden to prove CWSNC's investments recovered under the WSIC mechanism are reasonably and prudently incurred as required by N.C.G.S. § 62-133.12 and Commission Rule R7-39 shall remain with CWSNC;

16. That in the Company's next general rate case filing CWSNC shall ensure that its NCUC Form W-1, Item 26 is reconciled with the Company's bill data to ensure that the filing does not include double bills, that the Company accounts for multi-unit

[21] CWSNC's tariffs will be revised to reflect the change in taxability of CIAC based on the process outlined in Ordering Paragraph 4 of the Commission's February 11, 2020 Order, in Docket Nos. W-100, Sub 57 and W-100, Sub 62.

customers, and that other bills produced, such as final bills, late notices, re-bills, or other miscellaneous bills are not included in the NCUC Form W-1, Item 26 filing; and

17. That the Chief Clerk shall establish Docket No. W-354, Sub 364A as the single docket to be used for all future WSIC and SSIC filings, orders, and reporting requirements and shall close Docket No. W-354, Sub 360A.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service

in

ALL OF ITS SERVICE AREAS IN NORTH CAROLINA

(excluding Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills, Glen Arbor/North Bend, Bradfield Farms, Silverton, Woodland Farms, and Larkhaven Subdivisions, and Hawthorne at the Green Apartments

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 28.92
1" meter	$ 72.30
1 1/2" meter	$ 144.60
2" meter	$ 231.36
3" meter	$ 433.80
4" meter	$ 723.00
6" meter	$1,446.00

Usage Charge:

A. Treated Water/1,000 gallons $ 8.27

B. Untreated Water/1,000 gallons
(Brandywine Bay Irrigation Water) $ 4.23

C. Purchased Water for Resale, per 1,000 gallons:

Service Area	Bulk Provider		
Carolina Forest	Montgomery County	$	3.19
High Vista Estates	City of Hendersonville	$	3.40
Riverbend	Town of Franklin	$	7.50
Riverpointe	Charlotte Water	$	6.48
Whispering Pines	Town of Southern Pines	$	3.28
White Oak Plantation/			
Lee Forest	Johnston County	$	2.65
Winston Plantation	Johnston County	$	2.65
Winston Point	Johnston County	$	2.65
Woodrun	Montgomery County	$	3.19
Yorktown	City of Winston Salem	$	5.79
Zemosa Acres	City of Concord	$	5.41
Carolina Trace	City of Sanford	$	2.21

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

When because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit or other structure separately, the following will apply:

Sugar Mountain Service Area:
Where service to multiple units or other structures is provided through a single meter, the average usage for each unit or structure served by that meter will be calculated. Each unit or structure will be billed based upon that average usage plus the base monthly charge for a <1" meter.

Mount Mitchell Service Area:
Service will be billed based upon the Commission-approved monthly flat rate.

Monthly Flat Rate Service: (Billed in Arrears) $ 58.54

Availability Rate: (Semiannual)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 27.15

Availability Rate: (Monthly)

Applicable only to property owners in Linville Ridge Subdivision $ 13.60

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 10.05

Availability Rate: (Monthly rate, billed quarterly))

Applicable only to property owners in Connestee Falls	$ 5.30
Meter Testing Fee: [1/]	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charge: [2/]

If water service is cut off by utility for good cause	$ 42.00
If water service is discontinued at customer's request	$ 42.00

Reconnection Charge: [3/](Flat-rate water customers)

If water service is cut off by utility for good cause	Actual Cost

Management Fee: (in the following subdivisions only)

(Per connection)

Wolf Laurel	$150.00
Covington Cross Subdivision (Phases 1 & 2)	$100.00

Oversizing Fee: (in the following subdivision only)

(One-time charge per single-family equivalent)

Winghurst	$400.00

Meter Fee:

For <1" meters	$ 50.00
For meters 1" or larger	Actual Cost
Irrigation Meter Installation:	Actual Cost

SEWER RATES AND CHARGES

Monthly Metered Sewer Service:

A. Base Facility Charge:

Residential (zero usage)	$ 58.91

Commercial (based on meter size with zero usage)

< 1" meter	$ 58.91
1" meter	$ 147.28
1 1/2" meter	$ 294.55
2" meter	$ 471.28
3" meter	$ 883.65
4" meter	$1,472.75
6" meter	$2,945.50

B. Usage charge, per 1,000 gallons	$ 4.59

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial)	$ 41.24

Usage charge, per 1,000 gallons
(based on purchased water consumption)

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 5.57
Kings Grant	Two Rivers Utilities	$ 3.98
College Park	Town of Dallas	$ 7.33

Monthly Flat Rate Service:	$ 73.73

Multi-residential customers who are served by a master meter shall be charged the flat rate per unit.	$ 73.73

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 7.29
Monthly Collection Charge (Residential and Commercial)	$ 41.24
Usage Charge, per 1,000 gallons (based on metered water from the water supplier)	$ 6.32

Regalwood and White Oak Estates Subdivision Service Area:

Monthly Flat Rate Sewer Service	
Residential Service	$ 73.73
White Oak High School	$2,187.33
Child Castle Daycare	$ 280.41
Pantry	$ 153.76

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area, and Highland Shores Subdivision:

Monthly Sewer Rates:

Residential	
Collection charge/dwelling unit	$ 41.24
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 110.74
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 110.74
Monthly collection and treatment charge for customers who do not take water service	$ 110.74
Treatment charge per dwelling unit	
Small (less than 2,500 gallons per month)	$ 78.50
Medium (2,500 to 10,000 gallons per month)	$ 139.50
Large (over 10,000 gallons per month)	$ 219.50
Collection Charge (per 1,000 gallons)	$ 13.93

The Ridges at Mountain Harbour:

Monthly Sewer Rates:

Collection charge (Residential and Commercial)	$ 41.24
Treatment charge (Residential and Commercial)	
< 1” meter	$ 18.42
2” meter	$ 147.36

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 10.20

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 5.75

New Sewer Customer Charge: [4/] $ 27.00

Reconnection Charge: [5/]

If sewer service is cut off by utility for good cause: Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for processing NSF Checks: $ 25.00

Bills Due: On billing date

Bills Past Due: 21 days after billing date

Billing Frequency: Bills shall be rendered monthly in all service areas, except for Mt. Carmel, which will be billed bimonthly.

Availability rates will be billed quarterly in advance for Connestee Falls, semiannually in advance for Carolina Forest, Woodrun, and Fairfield Sapphire Valley, and monthly for Linville Ridge.

Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

[2/] Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

[3/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice.

[4/] This charge shall be waived if customer is also a water customer within the same service area.

[5/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area. Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 364, on this the 31st day of March, 2020.

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service

in

TREASURE COVE, REGISTER PLACE ESTATES, NORTH HILLS, GLEN ARBOR/NORTH BEND SUBDIVISIONS, FAIRFIELD HARBOUR SERVICE AREA, BRADFIELD FARMS SUBDIVISION, LARKHAVEN SUBDIVISION, SILVERTON, AND WOODLAND FARMS SUBDIVISIONS, AND HAWTHORNE AT THE GREEN APARTMENTS

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 17.30
1" meter	$ 43.25
1 1/2" meter	$ 86.50
2" meter	$138.40

Usage Charge, per 1,000 gallons	$ 4.20

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	$ 3.55

Connection Charge:

Treasure Cove Subdivision	$ 0.00
North Hills Subdivision	$ 100.00
Glen Arbor/North Bend Subdivision	$ 0.00
Register Place Estates	$ 500.00

Fairfield Harbor: 1/

All Areas Except Harbor Pointe II Subdivision

Recoupment of capital fees per tap	$ 335.00
Connection charge per tap	$ 140.00

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

Recoupment of capital fee per tap	$ 650.00
Connection charge per tap	$ 320.00

Bradfield Farms:

Connection charge per tap	None

Meter Testing Fee: 2/	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charge: 3/

If water service is cut off by utility for good cause	$ 42.00
If water service is discontinued at customer's request	$ 42.00
New Meter Charge:	Actual Cost
Irrigation Meter Installation:	Actual Cost

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 53.91
Bulk Flat Rate, per REU	$ 53.91

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 53.91

Monthly Metered Rates
(based on meter size with zero usage)

<1” meter	$ 44.62
1” meter	$ 111.55
1 1/2” meter	$ 223.10
2” meter	$ 356.96

Usage Charge, per 1,000 gallons $ 2.25

Bulk Sewer Service for Hawthorne at the Green Apartments: [4/]

Bulk Flat Rate, per REU $ 53.91

(To be collected from Hawthorne and delivered to Carolina Water Service, Inc. of North Carolina for treatment of the Hawthorne wastewater pursuant to Docket No. W-218, Sub 291)

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area $ 2.85

Connection Charge

Fairfield Harbour: [1/]

All Areas Except Harbor Pointe II Subdivision

Recoupment of capital fees per tap	$ 735.00
Connection charge per tap	$ 140.00

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

Recoupment of capital fee per tap	$ 2,215.00
Connection charge per tap	$ 310.00

Bradfield Farms:

Connection charge per tap None

New Sewer Customer Charge: [5/] $ 27.00

Reconnection Charge: [6/]
If sewer service is cut off by utility for good cause: Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be monthly for service in arrears. Availability billings semiannually in advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

1/ The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

2/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

3/ Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

4/ Each Apartment building will be considered 92.42% occupied on an ongoing basis for billing purposes as soon as the certificate of occupancy is issued for that apartment building.

[5/] This charge shall be waived if customer is also a water customer within the same service area.

[6/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area. Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 364, on this the 31st day of March, 2020.

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

SCHEDULE OF CONNECTION FEES

FOR WATER UTILITY SERVICE UNDER UNIFORM RATES

Uniform Connection Fees: [1/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single-Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$ 400.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amherst	$ 250.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Blue Mountain at Wolf Laurel	$ 925.00	$ 0.00
Buffalo Creek, Phase I, II, III, IV	$ 825.00	$ 0.00
Carolina Forest	$ 0.00	$ 0.00
Chapel Hills	$ 150.00	$ 400.00
Eagle Crossing	$ 0.00	$ 0.00
Elk River Development	$1,000.00	$ 0.00
Forest Brook/Old Lamp Place	$ 0.00	$ 0.00
Harbour	$ 75.00	$ 0.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Lemmond Acres	$ 0.00	$ 0.00
Linville Ridge	$ 400.00	$ 0.00
Monterrey (Monterrey LLC)	$ 0.00	$ 0.00
Quail Ridge	$ 750.00	$ 0.00
Queens Harbour/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Riverwood, Phase 6E (Johnston County)	$ 825.00	$ 0.00
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00

Subdivision	CC	PMF
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
The Ridges at Mountain Harbour	$2,500.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$1,080.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

Other Connection Fees:

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

Amber Acres, Amber Acres North, Amber Ridge, Ashley Hills North, Bishop Pointe, Carriage Manor, Country Crossing, Covington Cross, Heather Glen, Hidden Hollow, Jordan Woods, Lindsey Point, Neuse Woods, Oakes Plantation, Randsdell Forest, Rutledge Landing, Sandy Trails, Stewart's Ridge, Tuckahoe, Wilder's Village and Forest Hill Subdivisions

Connection Charge:

A. 5/8" meter	$ 500.00
B. All other meter sizes	Actual cost of meter and installation

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision	CC
Lindsey Point Subdivision	$ 0.00
Amber Acres North, Sections II & IV	$ 570.00
Fairfield Mountain/Apple Valley (a.ka.a Rumbing Bald) Service Area	$ 500.00
Highland Shores Subdivision	$ 500.00
Laurel Mountain Estates	$ 0.00
Carolina Trace	$ 605.00
Connestee Falls	$ 600.00

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

<u>All Areas Except Holly Forest XI, Holly Forest XIV, Holly Forest XV, Whisper Lake I, Whisper Lake II, Whisper Lake III, Deer Run, Lonesome Valley Phases I and II, and Chattooga Ridge</u>

Recoupment of Capital Fee (RCF) [2/]	$ 0.00
Connection charge	$ 400.00

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows.

Subdivision	CC	RCF
Holly Forest XI	$ 400.00	$2,400.00
Holly Forest XIV	$ 400.00	$ 250.00
Holly Forest XV	$ 400.00	$ 500.00
Whispering Lake Phase I	$ 400.00	$1,250.00
Whispering Lake Phases II and III	$ 400.00	$2,450.00
Deer Run	$ 400.00	$1,900.00
Lonesome Valley Phases I and II	$ 0.00	$ 0.00
Chattooga Ridge	$ 0.00	$ 0.00

[1/] These fees are only applicable one time, when the unit is initially connected to the system.
[2/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 364, on this the 31st day of March, 2020.

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

SCHEDULE OF CONNECTION FEES FOR

SEWER UTILITY SERVICE UNDER UNIFROM RATES

Uniform Connection Fees: [1/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single-Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amber Acres North (Phases II & IV)	$ 815.00	$ 0.00
Ashley Hills	$ 0.00	$ 0.00
Amherst	$ 500.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Brandywine Bay	$ 100.00	$1,456.00
Camp Morehead by the Sea	$ 100.00	$1,456.00
Elk River Development	$1,200.00	$ 0.00
Hammock Place	$ 100.00	$1,456.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 30.00	$ 0.00
Independent/Hemby Acres/Beacon Hills (Griffin Bldrs.)	$ 0.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Kynwood	$ 0.00	$ 0.00
Mt. Carmel/Section 5A	$ 500.00	$ 0.00
Queens Harbor/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Steeplechase (Spartabrook)	$ 0.00	$ 0.00
The Ridges at Mountain Harbour	$2,500.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00

Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston pointe (Phase 1A)	$1,400.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

Other Connection Fees:

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows.

Subdivision

Carolina Pines

Residential	$1,350.00 per unit (including single-family homes, condominiums, apartments, and mobile homes)
Hotels	$750.00 per unit
Nonresidential	$3.57 per gallon of daily design of discharge or $900.00 per unit, whichever is greater

Subdivision	CC
Fairfield Mountain/Apply Valley (a.k.a. Rumbling Bald)	
Service Area	$ 550.00
Highland Shores	$ 550.00
Carolina Trace	$ 533.00
Connestee Falls	$ 400.00

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

All Areas Except Holly Forest XIV, Holly Forest XV, Deer Run, and Lonesome Valley Phases I and II

Recoupment of Capital Fee (RCF) [2/]	$ 0.00
Connection charge	$ 550.00

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision	CC	RCF
Holly Forest XIV	$ 550.00	$1,650.00
Holly Forest XV	$ 550.00	$ 475.00
Deer Run	$ 550.00	$1,650.00
Lonesome Valley Phases I and II	$ 0.00	$ 0.00

[1/] These fees are only applicable one time, when the unit is initially connected to the system.
[2/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 364

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina	)))))))	NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to increase rates for water and sewer utility service in all of its service areas in North Carolina. The new approved rates are as follows:

WATER RATES AND CHARGES

(Excluding Fairfield Harbour Service Area and Treasure Cove, Register Place Estates, North Hills, Glen Arbor/North Bend, Bradfield Farms, Larkhaven, Silverton, and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments

Uniform Water Customers:

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1” meter	$ 28.92
1” meter	$ 72.30
1 1/2” meter	$ 144.60
2” meter	$ 231.36
3” meter	$ 433.80
4” meter	$ 723.00
6” meter	$1,446.00

Usage Charge:

A. Treated Water/1,000 gallons	$ 8.27	
B. Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)		$ 4.23

C. Purchased Water for Resale, per1,000 gallons:

Service Area	Bulk Provider		
Carolina Forest	Montgomery County	$	3.19
High Vista Estates	City of Hendersonville	$	3.40
Riverbend	Town of Franklin	$	7.50
Riverpointe	Charlotte Water	$	6.48
Whispering Pines	Town of Southern Pines	$	3.28
White Oak Plantation/ Lee Forest	Johnston County	$	2.65
Winston Plantation	Johnston County	$	2.65
Winston Point	Johnston County	$	2.65
Woodrun	Montgomery County	$	3.19
Yorktown	City of Winston Salem	$	5.79
Zemosa Acres	City of Concord	$	5.41
Carolina Trace	City of Sanford	$	2.21

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

When because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit or other structure separately, the following will apply:

Sugar Mountain Service Area:
Where service to multiple units or other structures is provided through a single meter, the average usage for each unit or structure served by that meter will be calculated. Each unit or structure will be billed based upon that average usage plus the base monthly charge for a <1" meter.

Mount Mitchell Service Area:
Service will be billed based upon the Commission-approved monthly flat rate.

Monthly Flat Rate Service: (Billed in Arrears) $ 58.54
Availability Rate: (Semiannual)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 27.15

Availability Rate: (Monthly)

Applicable only to property owners in Linville Ridge Subdivision $ 13.60

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 10.05

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 5.30

SEWER RATES AND CHARGES

(Excluding Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven, Silverton, and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments

Uniform Sewer Customers:

Monthly Metered Sewer Service:

Base Facility Charge:

Residential (zero usage)	$ 58.91

Commercial (based on meter size with zero usage)

< 1" meter	$ 58.91
1" meter	$ 147.28
1 1/2" meter	$ 294.55
2" meter	$ 471.28
3" meter	$ 883.65
4" meter	$1,472.75
6" meter	$2,945.50

Usage charge, per 1,000 gallons	$ 4.59

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (residential and commercial)	$ 41.24

Usage charge, per 1,000 gallons based on purchased water consumption

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 5.57
Kings Grant	Two Rivers Utilities	$ 3.98
College Park	Town of Dallas	$ 7.33

Monthly Flat Rate Service: $ 73.73

Multi-residential customers who are served by a master meter shall be charged the flat rate per unit. $ 73.73

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 7.29
Monthly Collection Charge (Residential and commercial)	$ 41.24
Usage Charge/1,000 gallons based on purchased water	$ 6.32

Regalwood and White Oak Estates Subdivision Service Area:

Monthly Flat Rate Sewer Service

Residential Service	$ 73.73
White Oak High School	$2,187.33
Child Castle Daycare	$ 280.41
Pantry	$ 153.76

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area, Highland Shores Subdivisions and Laurel Mountain Estates
Monthly Sewer Rates:

Residential:

Collection charge/dwelling unit	$ 41.24
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 110.74

Commercial and Other:

Minimum monthly collection and treatment charge	$ 110.74
Monthly collection and treatment charge for customers Who do not take water service (per single family unit)	$ 110.74

Treatment charge per dwelling unit

Small (less than 2,500 gallons per month)	$ 78.50
Medium (2,500 to 10,000 gallons per month)	$ 139.50
Large (over 10,000 gallons per month)	$ 219.50

Collection Charge (per 1,000 gallons) $ 13.93

The Ridges at Mountain Harbour:

Monthly Sewer Rates:

Collection charge (Residential and Commercial) $ 41.24

Treatment Charge (Residential and Commercial)

< 1 inch meter	$ 18.42
2 inch meter	$ 147.36

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area $ 10.20

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls $ 5.75

RATE ADJUSTMENT MECHANISM:

The Commission-authorized water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism continues in effect and will now be applicable to all customers in CWSNC's North Carolina service areas. It has been reset at zero in the Docket No. W-354, Sub 364 rate case, but CWSNC may, under the Rules and Regulations of the Commission, next apply for a rate surcharge on July 31, 2020 to become effective October 1, 2020. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 360A" and "W-354, Sub 364A" .

<u>CREDIT/REFUNDS DUE TO REDUCTION IN FEDERAL CORPORATE INCOME TAX RATE</u>:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017.

With respect to excess deferred income taxes (EDIT) resulting from the reduction in the federal corporate income tax rate, the Commission is requiring that: (1) CWSNC shall continue to flow back the federal protected EDIT to customers in accordance with the Reverse South Georgia Method as ordered by the Commission in CWSNC's last rate case (Docket No. W-354, Sub 360), and (2) CWSNC shall refund the remaining federal unprotected EDIT to customers through a levelized rider over a period of 24 months as requested by CWSNC instead of the remaining 35-month period as originally ordered by the Commission in Docket No. W-354, Sub 360.

CWSNC will provide the applicable dollar amount concerning the federal EDIT rider (refund) shown as a separate line item on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 364

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina	)	NOTICE TO CUSTOMERS IN TREASURE COVE, REGISTER PLACE ESTATES, NORTH HILLS, AND GLEN ARBOR/NORTH BEND SUBDIVISIONS, FAIRFIELD HARBOUR SERVICE AREA, BRADFIELD FARMS, LARKHAVEN, SILVERTON, AND WOODLAND FARMS SUBDIVISIONS, AND HAWTHORNE AT THE GREEN APARTMENTS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina to charge the following new rates for water and sewer utility service in Treasure Cove, Register Place Estates, North Hills, and Glen Arbor/North Bend Subdivisions, Fairfield Harbour Service Area, Bradfield Farms, Larkhaven, Silverton, and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments:

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)	
< 1” meter	$ 17.30
1” meter	$ 43.25
1 1/2” meter	$ 86.50
2” meter	$ 138.40
Usage Charge, per 1,000 gallons	$ 4.20

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	$ 3.55

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 53.91
Bulk Flat Rate, per REU	$ 53.91

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 53.91
Monthly Metered Rates (based on meter size with zero usage)	
<1” meter	$ 44.62
1” meter	$111.55
1 1/2” meter	$223.10
2” meter	$356.96
Usage Charge, per 1,000 gallons	$ 2.25

Bulk Sewer Service for Hawthorne at the Green Apartments:

Bulk Flat Rate, per REU	$ 53.91

(To be collected from Hawthorne and delivered to Carolina Water Service, Inc. of North Carolina for treatment of the Hawthorne wastewater pursuant to Docket No. W-218, Sub 291)

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	$ 2.85

RATE ADJUSTMENT MECHANISM:

The Commission-authorized water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism continues in effect and will now be applicable to all customers in CWSNC’s North Carolina service areas. It has been reset at zero in the Docket No. W-354, Sub 364 rate case, but CWSNC may, under the Rules and Regulations of the Commission, next apply for a rate surcharge on July 31, 2020, to become effective October 1, 2020. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 360A" and "W-354 Sub 364A".

CREDIT/REFUNDS DUE TO REDUCTION IN FEDERAL CORPORATE INCOME TAX RATE:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017.

With respect to excess deferred income taxes (EDIT) resulting from the reduction in the federal corporate income tax rate, the Commission is requiring that: (1) CWSNC shall continue to flow back the federal protected EDIT to customers in accordance with the Reverse South Georgia Method as ordered by the Commission in CWSNC's last rate case (Docket No. W-354, Sub 360), and (2) CWSNC shall refund the remaining federal unprotected EDIT to customers through a levelized rider over a period of 24 months as requested by CWSNC instead of the remaining 35-month period as originally ordered by the Commission in Docket No. W-354, Sub 360.

CWSNC will provide the applicable dollar amount concerning the federal EDIT rider (refund) shown as a separate line item on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of March, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notices to Customers issued by the North Carolina Utilities Commission in Docket No. W-354, Subs 363, 364, and 365, and the Notices were mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2020.

By:____________________________________
Signature

____
Name of Utility Company

The above named Applicant, ____________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notices to Customers were mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-354, Subs 363, 364, and 365.

Witness my hand and notarial seal, this the ___ day of ___________, 2020.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ______________________________________
Date

KROLL

U.S. Capital Markets Performance
by Asset Class 1926–2021

2022
SBBI® Yearbook

STOCKS, BONDS, BILLS, AND INFLATION®

Roger G. Ibbotson

The Risk-Free Asset

The equity risk premium can be calculated for a variety of time horizons when given the choice of risk-free asset to be used in the calculation. The long-horizon, intermediate-horizon, and short-horizon equity risk premia calculated in Exhibit 10.8 and Exhibit 10.9 use the income return from (i) a 20-year Treasury bond, (ii) a 5-year Treasury bond, and (iii) a 30-day Treasury bill, respectively.[215]

20-Year vs. 30-Year Treasuries

The U.S. Treasury periodically changes the maturities that it issues. For example, in April 1986 the U.S. Treasury stopped issuing 20-year Treasuries, and from October 2001 through January 2006 the U.S. Treasury did not issue 30-year bonds (it resumed issuing 30-year Treasury bonds in February 2006), making the 10-year bond the longest-term Treasury security issued over the October 2001–January 2006 period. Most recently, on January 16, 2020 the U.S. Department of the Treasury announced it plans to issue a 20-year nominal coupon bond in the first half of calendar year 2020, the first time a 20-year maturity will be offered since March 1986.[216,217]

Our methodology for estimating the long-horizon equity risk premium makes use of the income return on a 20-year Treasury bond. While a 30-year bond is theoretically more correct when dealing with the long-term nature of business valuation,[218] 30-year Treasury securities have an issuance history that is on-again-off-again. Ibbotson Associates creates a series of returns using bonds on the market with approximately 20 years to maturity because Treasury bonds of this maturity are available over a long history, while Treasury bonds of 30-years are not.

Income Return

Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation.

The total return comprises three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected

215 For U.S. Treasury Bills, the income return and total return are the same.

216 To learn more, visit the U.S. Department of the Treasury website at: https://home.treasury.gov/news/press-releases/sm878.

217 See Kate Davidson, "Treasury to Issue New 20-Year Bond in First Half of 2020", The Wall Street Journal, January 16, 2020 at: https://www.wsj.com/articles/treasury-to-issue-new-20-year-bond-in-first-half-of-2020-11579217450.

218 An equity risk premium is an input in developing cost of capital estimates (i.e., "expected return", "required return", or "discount rate") for use in a discounted cash flow model. **Note:** The four Kroll (formerly Duff & Phelps) "Valuation Handbooks" have been transitioned from print to an online delivery platform, the "Cost of Capital Navigator". The Cost of Capital Navigator is an interactive, web-based platform that guides finance and investment professionals through the process of estimating cost of capital, globally. The Cost of Capital Navigator includes four modules: (i) the U.S. Cost of Capital Module, (ii) the U.S. Industry Benchmarking Module, (iii) the International Cost of Capital Module, and (iv) the International Industry Benchmarking Module. To learn more, visit kroll.com/costofcapitalnavigator.

fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.

Arithmetic vs. Geometric Mean

The equity risk premium data presented in this book are arithmetic average risk premiums as opposed to geometric average risk premiums. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building-block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number.

This is because both the CAPM and the building-block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance because it represents the compound average return.

Appropriate Historical Period

The equity risk premium can be estimated using any historical time period. For the U.S., market data exist at least as far back as the late 1800s. Therefore, it is possible to estimate the equity risk premium using data that covers roughly the past 125 years.

Our equity risk premium covers 1926 to the present. The original data source for the time series comprising the equity risk premium is the Center for Research in Security Prices. CRSP chose to begin its analysis of market returns with 1926 for two main reasons. CRSP determined that 1926 was approximately when quality financial data became available. They also made a conscious effort to include the period of extreme market volatility from the late 1920s and early 1930s; 1926 was chosen because it includes one full business cycle of data before the market crash of 1929.

Implicit in using history to forecast the future is the assumption that investors' expectations for future outcomes conform to past results. This method assumes that the price of taking on risk changes only slowly, if at all, over time. This "future equals the past" assumption is most applicable to a random time-series variable. A time-series variable is random if its value in one period is independent of its value in other periods.

Choosing an Appropriate Historical Period

The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable. Furthermore, because an average of the realized

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Large-Capitalization Stocks: Total Return
From 1926 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1926	0.0000	-0.0385	-0.0575	0.0253	0.0179	0.0457	0.0479	0.0248	0.0252	-0.0284	0.0347	0.0196	1926	0.1162
1927	-0.0193	0.0537	0.0087	0.0201	0.0607	-0.0067	0.0670	0.0515	0.0450	-0.0502	0.0721	0.0279	1927	0.3749
1928	-0.0040	-0.0125	0.1101	0.0345	0.0197	-0.0385	0.0141	0.0803	0.0259	0.0168	0.1292	0.0049	1928	0.4361
1929	0.0583	-0.0019	-0.0012	0.0176	-0.0362	0.1140	0.0471	0.1028	-0.0476	-0.1973	-0.1246	0.0282	1929	-0.0842
1930	0.0639	0.0259	0.0812	-0.0080	-0.0096	-0.1625	0.0386	0.0141	-0.1282	-0.0855	-0.0089	-0.0706	1930	-0.2490
1931	0.0502	0.1193	-0.0675	-0.0935	-0.1279	0.1421	-0.0722	0.0182	-0.2973	0.0896	-0.0798	-0.1400	1931	-0.4334
1932	-0.0271	0.0570	-0.1158	-0.1997	-0.2196	-0.0022	0.3815	0.3869	-0.0346	-0.1349	-0.0417	0.0565	1932	-0.0819
1933	0.0087	-0.1772	0.0353	0.4256	0.1683	0.1338	-0.0862	0.1206	-0.1118	-0.0855	0.1127	0.0253	1933	0.5399
1934	0.1069	-0.0322	0.0000	-0.0251	-0.0736	0.0229	-0.1132	0.0611	-0.0033	-0.0286	0.0942	-0.0010	1934	-0.0144
1935	-0.0411	-0.0341	-0.0286	0.0980	0.0409	0.0699	0.0850	0.0280	0.0256	0.0777	0.0474	0.0394	1935	0.4767
1936	0.0670	0.0224	0.0268	-0.0751	0.0545	0.0333	0.0701	0.0151	0.0031	0.0775	0.0134	-0.0029	1936	0.3392
1937	0.0390	0.0191	-0.0077	-0.0809	-0.0024	-0.0504	0.1045	-0.0483	-0.1403	-0.0981	-0.0866	-0.0459	1937	-0.3503
1938	0.0152	0.0674	-0.2487	0.1447	-0.0330	0.2503	0.0744	-0.0226	0.0166	0.0776	-0.0273	0.0401	1938	0.3112
1939	-0.0674	0.0390	-0.1339	-0.0027	0.0733	-0.0612	0.1105	-0.0648	0.1673	-0.0123	-0.0398	0.0270	1939	-0.0041
1940	-0.0336	0.0133	0.0124	-0.0024	-0.2289	0.0809	0.0341	0.0350	0.0123	0.0422	-0.0316	0.0009	1940	-0.0978
1941	-0.0463	-0.0060	0.0071	-0.0612	0.0183	0.0578	0.0579	0.0010	-0.0068	-0.0657	-0.0284	-0.0407	1941	-0.1159
1942	0.0161	-0.0159	-0.0652	-0.0400	0.0796	0.0221	0.0337	0.0164	0.0290	0.0678	-0.0021	0.0549	1942	0.2034
1943	0.0737	0.0583	0.0545	0.0035	0.0552	0.0223	-0.0526	0.0171	0.0263	-0.0108	-0.0654	0.0617	1943	0.2590
1944	0.0171	0.0042	0.0195	-0.0100	0.0505	0.0543	-0.0193	0.0157	-0.0008	0.0023	0.0133	0.0374	1944	0.1975
1945	0.0158	0.0683	-0.0441	0.0902	0.0195	-0.0007	-0.0180	0.0641	0.0438	0.0322	0.0396	0.0116	1945	0.3644
1946	0.0714	-0.0641	0.0480	0.0393	0.0288	-0.0370	-0.0239	-0.0674	-0.0997	-0.0060	-0.0027	0.0457	1946	-0.0807
1947	0.0255	-0.0077	-0.0149	-0.0363	0.0014	0.0554	0.0381	-0.0203	-0.0111	0.0238	-0.0175	0.0233	1947	0.0571
1948	-0.0379	-0.0388	0.0793	0.0292	0.0879	0.0054	-0.0508	0.0158	-0.0276	0.0710	-0.0961	0.0346	1948	0.0550
1949	0.0039	-0.0296	0.0328	-0.0179	-0.0258	0.0014	0.0650	0.0219	0.0263	0.0340	0.0175	0.0486	1949	0.1879
1950	0.0197	0.0199	0.0070	0.0486	0.0509	-0.0548	0.0119	0.0443	0.0592	0.0093	0.0169	0.0513	1950	0.3171
1951	0.0637	0.0157	-0.0156	0.0509	-0.0299	-0.0228	0.0711	0.0478	0.0013	-0.0103	0.0096	0.0424	1951	0.2402
1952	0.0181	-0.0282	0.0503	-0.0402	0.0343	0.0490	0.0196	-0.0071	-0.0176	0.0020	0.0571	0.0382	1952	0.1837
1953	-0.0049	-0.0106	-0.0212	-0.0237	0.0077	-0.0134	0.0273	-0.0501	0.0034	0.0540	0.0204	0.0053	1953	-0.0099
1954	0.0536	0.0111	0.0325	0.0516	0.0418	0.0031	0.0589	-0.0275	0.0851	-0.0167	0.0909	0.0534	1954	0.5262
1955	0.0197	0.0098	-0.0030	0.0396	0.0055	0.0841	0.0622	-0.0025	0.0130	-0.0284	0.0827	0.0015	1955	0.3156
1956	-0.0347	0.0413	0.0710	-0.0004	-0.0593	0.0409	0.0530	-0.0328	-0.0440	0.0066	-0.0050	0.0370	1956	0.0656
1957	-0.0401	-0.0264	0.0215	0.0388	0.0437	0.0004	0.0131	-0.0505	-0.0602	-0.0302	0.0231	-0.0395	1957	-0.1078

*Compound Annual Return

Appendix A-1

Large-Capitalization Stocks: Total Return
From 1926 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1958	0.0445	-0.0141	0.0328	0.0337	0.0212	0.0279	0.0449	0.0176	0.0501	0.0270	0.0284	0.0535	1958	0.4336
1959	0.0053	0.0049	0.0020	0.0402	0.0240	-0.0022	0.0363	-0.0102	-0.0443	0.0128	0.0186	0.0292	1959	0.1196
1960	-0.0700	0.0147	-0.0123	-0.0161	0.0326	0.0211	-0.0234	0.0317	-0.0590	-0.0007	0.0465	0.0479	1960	0.0047
1961	0.0645	0.0319	0.0270	0.0051	0.0239	-0.0275	0.0342	0.0243	-0.0184	0.0298	0.0447	0.0046	1961	0.2689
1962	-0.0366	0.0209	-0.0046	-0.0607	-0.0811	-0.0803	0.0652	0.0208	-0.0465	0.0064	0.1086	0.0153	1962	-0.0873
1963	0.0506	-0.0239	0.0370	0.0500	0.0193	-0.0188	-0.0022	0.0535	-0.0097	0.0339	-0.0046	0.0262	1963	0.2280
1964	0.0283	0.0147	0.0165	0.0075	0.0162	0.0178	0.0195	-0.0118	0.0301	0.0096	0.0005	0.0056	1964	0.1648
1965	0.0345	0.0031	-0.0133	0.0356	-0.0030	-0.0473	0.0147	0.0272	0.0334	0.0289	-0.0031	0.0106	1965	0.1245
1966	0.0062	-0.0131	-0.0205	0.0220	-0.0492	-0.0146	-0.0120	-0.0725	-0.0053	0.0494	0.0095	0.0002	1966	-0.1006
1967	0.0798	0.0072	0.0409	0.0437	-0.0477	0.0190	0.0468	-0.0070	0.0342	-0.0276	0.0065	0.0278	1967	0.2398
1968	-0.0425	-0.0261	0.0110	0.0834	0.0161	0.0105	-0.0172	0.0164	0.0400	0.0087	0.0531	-0.0402	1968	0.1106
1969	-0.0068	-0.0426	0.0359	0.0229	0.0026	-0.0542	-0.0587	0.0454	-0.0236	0.0459	-0.0297	-0.0177	1969	-0.0850
1970	-0.0743	0.0558	0.0044	-0.0875	-0.0578	-0.0466	0.0769	0.0478	0.0362	-0.0083	0.0506	0.0597	1970	0.0386
1971	0.0432	0.0117	0.0394	0.0389	-0.0391	0.0033	-0.0387	0.0388	-0.0044	-0.0392	0.0002	0.0888	1971	0.1430
1972	0.0206	0.0277	0.0083	0.0068	0.0197	-0.0194	0.0048	0.0369	-0.0025	0.0118	0.0481	0.0142	1972	0.1900
1973	-0.0149	-0.0352	0.0008	-0.0383	-0.0163	-0.0040	0.0407	-0.0341	0.0427	0.0017	-0.1109	0.0198	1973	-0.1469
1974	-0.0072	-0.0007	-0.0205	-0.0359	-0.0302	-0.0113	-0.0742	-0.0864	-0.1152	0.1681	-0.0488	-0.0156	1974	-0.2647
1975	0.1272	0.0638	0.0254	0.0510	0.0477	0.0477	-0.0644	-0.0176	-0.0312	0.0653	0.0282	-0.0081	1975	0.3723
1976	0.1217	-0.0084	0.0337	-0.0078	-0.0111	0.0443	-0.0048	-0.0018	0.0258	-0.0186	-0.0041	0.0561	1976	0.2393
1977	-0.0473	-0.0182	-0.0105	0.0042	-0.0196	0.0494	-0.0124	-0.0172	0.0016	-0.0390	0.0316	0.0075	1977	-0.0716
1978	-0.0574	-0.0203	0.0294	0.0902	0.0092	-0.0138	0.0583	0.0301	-0.0032	-0.0872	0.0215	0.0196	1978	0.0657
1979	0.0443	-0.0321	0.0596	0.0063	-0.0217	0.0435	0.0134	0.0577	0.0043	-0.0640	0.0475	0.0214	1979	0.1861
1980	0.0622	-0.0001	-0.0972	0.0462	0.0515	0.0316	0.0696	0.0101	0.0294	0.0202	0.1065	-0.0302	1980	0.3250
1981	-0.0418	0.0174	0.0400	-0.0193	0.0026	-0.0063	0.0021	-0.0577	-0.0493	0.0540	0.0413	-0.0256	1981	-0.0492
1982	-0.0131	-0.0559	-0.0052	0.0452	-0.0341	-0.0150	-0.0178	0.1214	0.0125	0.1151	0.0404	0.0193	1982	0.2155
1983	0.0372	0.0229	0.0369	0.0788	-0.0087	0.0389	-0.0295	0.0150	0.0138	-0.0116	0.0211	-0.0052	1983	0.2256
1984	-0.0056	-0.0352	0.0173	0.0095	-0.0554	0.0217	-0.0124	0.1104	0.0002	0.0039	-0.0112	0.0263	1984	0.0627
1985	0.0779	0.0122	0.0007	-0.0009	0.0578	0.0157	-0.0015	-0.0085	-0.0313	0.0462	0.0686	0.0484	1985	0.3173
1986	0.0056	0.0747	0.0558	-0.0113	0.0532	0.0169	-0.0559	0.0742	-0.0827	0.0577	0.0243	-0.0255	1986	0.1867
1987	0.1347	0.0395	0.0289	-0.0089	0.0087	0.0505	0.0507	0.0373	-0.0219	-0.2154	-0.0824	0.0761	1987	0.0525
1988	0.0421	0.0466	-0.0309	0.0111	0.0086	0.0459	-0.0038	-0.0339	0.0426	0.0278	-0.0143	0.0174	1988	0.1661
1989	0.0732	-0.0249	0.0233	0.0519	0.0405	-0.0057	0.0903	0.0195	-0.0041	-0.0232	0.0204	0.0240	1989	0.3169

*Compound Annual Return

Appendix A-1

Large-Capitalization Stocks: Total Return
From 1926 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1990	-0.0671	0.0129	0.0265	-0.0249	0.0975	-0.0067	-0.0032	-0.0904	-0.0487	-0.0043	0.0646	0.0279	1990	-0.0310
1991	0.0436	0.0715	0.0242	0.0024	0.0431	-0.0458	0.0466	0.0237	-0.0167	0.0134	-0.0403	0.1144	1991	0.3047
1992	-0.0186	0.0130	-0.0194	0.0294	0.0049	-0.0149	0.0409	-0.0205	0.0118	0.0035	0.0341	0.0123	1992	0.0762
1993	0.0084	0.0136	0.0211	-0.0242	0.0268	0.0029	-0.0040	0.0379	-0.0077	0.0207	-0.0095	0.0121	1993	0.1008
1994	0.0340	-0.0271	-0.0436	0.0128	0.0164	-0.0245	0.0328	0.0410	-0.0245	0.0225	-0.0364	0.0148	1994	0.0132
1995	0.0259	0.0390	0.0295	0.0294	0.0400	0.0232	0.0332	0.0025	0.0422	-0.0036	0.0439	0.0193	1995	0.3758
1996	0.0340	0.0093	0.0096	0.0147	0.0258	0.0038	-0.0442	0.0211	0.0563	0.0276	0.0756	-0.0198	1996	0.2296
1997	0.0625	0.0078	-0.0411	0.0597	0.0609	0.0448	0.0796	-0.0560	0.0548	-0.0334	0.0463	0.0172	1997	0.3336
1998	0.0111	0.0721	0.0512	0.0101	-0.0172	0.0406	-0.0106	-0.1446	0.0641	0.0813	0.0606	0.0576	1998	0.2858
1999	0.0418	-0.0311	0.0400	0.0387	-0.0236	0.0555	-0.0312	-0.0049	-0.0274	0.0633	0.0203	0.0589	1999	0.2104
2000	-0.0502	-0.0189	0.0978	-0.0301	-0.0205	0.0247	-0.0156	0.0621	-0.0528	-0.0042	-0.0788	0.0049	2000	-0.0910
2001	0.0355	-0.0912	-0.0634	0.0777	0.0067	-0.0243	-0.0098	-0.0626	-0.0808	0.0191	0.0767	0.0088	2001	-0.1189
2002	-0.0146	-0.0193	0.0376	-0.0606	-0.0074	-0.0712	-0.0780	0.0066	-0.1087	0.0880	0.0589	-0.0587	2002	-0.2210
2003	-0.0262	-0.0150	0.0097	0.0824	0.0527	0.0128	0.0176	0.0195	-0.0106	0.0566	0.0088	0.0524	2003	0.2868
2004	0.0184	0.0139	-0.0151	-0.0157	0.0137	0.0194	-0.0331	0.0040	0.0108	0.0153	0.0405	0.0340	2004	0.1088
2005	-0.0244	0.0210	-0.0177	-0.0190	0.0318	0.0014	0.0372	-0.0091	0.0081	-0.0167	0.0378	0.0003	2005	0.0491
2006	0.0265	0.0027	0.0124	0.0134	-0.0288	0.0014	0.0062	0.0238	0.0258	0.0326	0.0190	0.0140	2006	0.1579
2007	0.0151	-0.0196	0.0112	0.0443	0.0349	-0.0166	-0.0310	0.0150	0.0374	0.0159	-0.0418	-0.0069	2007	0.0549
2008	-0.0600	-0.0325	-0.0043	0.0487	0.0130	-0.0843	-0.0084	0.0145	-0.0891	-0.1679	-0.0718	0.0106	2008	-0.3700
2009	-0.0843	-0.1065	0.0876	0.0957	0.0559	0.0020	0.0756	0.0361	0.0373	-0.0186	0.0600	0.0193	2009	0.2646
2010	-0.0360	0.0310	0.0603	0.0158	-0.0799	-0.0523	0.0701	-0.0451	0.0892	0.0380	0.0001	0.0668	2010	0.1506
2011	0.0237	0.0343	0.0004	0.0296	-0.0113	-0.0167	-0.0203	-0.0543	-0.0703	0.1093	-0.0022	0.0102	2011	0.0211
2012	0.0448	0.0432	0.0329	-0.0063	-0.0601	0.0412	0.0139	0.0225	0.0258	-0.0185	0.0058	0.0091	2012	0.1600
2013	0.0518	0.0136	0.0375	0.0193	0.0234	-0.0134	0.0509	-0.0290	0.0314	0.0460	0.0305	0.0253	2013	0.3239
2014	-0.0346	0.0457	0.0084	0.0074	0.0235	0.0207	-0.0138	0.0400	-0.0140	0.0244	0.0269	-0.0025	2014	0.1369
2015	-0.0300	0.0575	-0.0158	0.0096	0.0129	-0.0194	0.0210	-0.0603	-0.0247	0.0844	0.0030	-0.0158	2015	0.0138
2016	-0.0496	-0.0013	0.0678	0.0039	0.0180	0.0026	0.0369	0.0014	0.0002	-0.0182	0.0370	0.0198	2016	0.1196
2017	0.0190	0.0397	0.0012	0.0103	0.0141	0.0062	0.0206	0.0031	0.0206	0.0233	0.0307	0.0111	2017	0.2183
2018	0.0573	-0.0369	-0.0254	0.0038	0.0241	0.0062	0.0372	0.0326	0.0057	-0.0684	0.0204	-0.0903	2018	-0.0438
2019	0.0801	0.0321	0.0194	0.0405	-0.0635	0.0705	0.0144	-0.0158	0.0187	0.0217	0.0363	0.0302	2019	0.3149
2020	-0.0004	-0.0823	-0.1235	0.1282	0.0476	0.0199	0.0564	0.0719	-0.0380	-0.0266	0.1095	0.0384	2020	0.1840
2021	-0.0101	0.0276	0.0438	0.0534	0.0070	0.0233	0.0238	0.0304	-0.0465	0.0701	-0.0069	0.0448	2021	0.2871

*Compound Annual Return

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Long-term Government Bonds: Income Returns
From 1926 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1926	0.0031	0.0028	0.0032	0.0030	0.0028	0.0033	0.0031	0.0031	0.0030	0.0030	0.0031	0.0030	1926	0.0373
1927	0.0030	0.0027	0.0029	0.0027	0.0028	0.0027	0.0027	0.0029	0.0027	0.0028	0.0027	0.0027	1927	0.0341
1928	0.0027	0.0025	0.0027	0.0026	0.0027	0.0027	0.0027	0.0029	0.0027	0.0030	0.0027	0.0029	1928	0.0322
1929	0.0029	0.0027	0.0028	0.0034	0.0030	0.0029	0.0032	0.0030	0.0032	0.0031	0.0026	0.0031	1929	0.0347
1930	0.0029	0.0026	0.0029	0.0027	0.0027	0.0029	0.0028	0.0026	0.0029	0.0027	0.0026	0.0028	1930	0.0332
1931	0.0028	0.0026	0.0029	0.0027	0.0026	0.0028	0.0027	0.0027	0.0027	0.0029	0.0031	0.0032	1931	0.0333
1932	0.0032	0.0032	0.0031	0.0030	0.0028	0.0028	0.0028	0.0028	0.0026	0.0027	0.0026	0.0027	1932	0.0369
1933	0.0027	0.0023	0.0027	0.0025	0.0028	0.0025	0.0026	0.0026	0.0025	0.0026	0.0025	0.0028	1933	0.0312
1934	0.0029	0.0024	0.0027	0.0025	0.0025	0.0024	0.0024	0.0024	0.0023	0.0027	0.0025	0.0025	1934	0.0318
1935	0.0025	0.0021	0.0022	0.0023	0.0023	0.0022	0.0024	0.0023	0.0023	0.0023	0.0024	0.0024	1935	0.0281
1936	0.0024	0.0023	0.0024	0.0022	0.0022	0.0024	0.0023	0.0023	0.0021	0.0023	0.0022	0.0022	1936	0.0277
1937	0.0021	0.0020	0.0022	0.0023	0.0022	0.0025	0.0024	0.0023	0.0023	0.0023	0.0024	0.0023	1937	0.0266
1938	0.0023	0.0021	0.0023	0.0022	0.0022	0.0021	0.0021	0.0022	0.0021	0.0022	0.0021	0.0022	1938	0.0264
1939	0.0021	0.0019	0.0021	0.0019	0.0020	0.0018	0.0019	0.0018	0.0019	0.0023	0.0020	0.0019	1939	0.0240
1940	0.0020	0.0018	0.0019	0.0018	0.0019	0.0019	0.0020	0.0019	0.0018	0.0018	0.0018	0.0017	1940	0.0223
1941	0.0016	0.0016	0.0018	0.0017	0.0017	0.0016	0.0016	0.0016	0.0016	0.0016	0.0014	0.0016	1941	0.0194
1942	0.0021	0.0019	0.0021	0.0020	0.0019	0.0021	0.0021	0.0021	0.0020	0.0021	0.0020	0.0021	1942	0.0246
1943	0.0020	0.0019	0.0021	0.0020	0.0019	0.0021	0.0021	0.0021	0.0020	0.0020	0.0021	0.0021	1943	0.0244
1944	0.0021	0.0020	0.0021	0.0020	0.0022	0.0020	0.0021	0.0021	0.0020	0.0021	0.0020	0.0020	1944	0.0246
1945	0.0021	0.0018	0.0020	0.0019	0.0019	0.0019	0.0018	0.0019	0.0018	0.0019	0.0018	0.0018	1945	0.0234
1946	0.0017	0.0015	0.0016	0.0017	0.0018	0.0016	0.0019	0.0017	0.0018	0.0019	0.0018	0.0019	1946	0.0204
1947	0.0018	0.0016	0.0018	0.0017	0.0017	0.0019	0.0018	0.0017	0.0018	0.0018	0.0017	0.0021	1947	0.0213
1948	0.0020	0.0019	0.0022	0.0020	0.0018	0.0021	0.0019	0.0021	0.0020	0.0019	0.0021	0.0020	1948	0.0240
1949	0.0020	0.0018	0.0019	0.0018	0.0020	0.0019	0.0017	0.0019	0.0017	0.0018	0.0017	0.0017	1949	0.0225
1950	0.0018	0.0016	0.0018	0.0016	0.0019	0.0017	0.0018	0.0018	0.0017	0.0019	0.0018	0.0018	1950	0.0212
1951	0.0020	0.0017	0.0019	0.0020	0.0021	0.0020	0.0023	0.0021	0.0019	0.0023	0.0021	0.0022	1951	0.0238
1952	0.0023	0.0021	0.0023	0.0022	0.0020	0.0022	0.0022	0.0021	0.0023	0.0023	0.0021	0.0024	1952	0.0266
1953	0.0023	0.0021	0.0025	0.0024	0.0024	0.0027	0.0025	0.0025	0.0025	0.0023	0.0024	0.0024	1953	0.0284
1954	0.0023	0.0022	0.0025	0.0022	0.0020	0.0025	0.0022	0.0023	0.0022	0.0021	0.0023	0.0023	1954	0.0279
1955	0.0022	0.0022	0.0024	0.0022	0.0025	0.0023	0.0023	0.0027	0.0024	0.0025	0.0024	0.0024	1955	0.0275
1956	0.0025	0.0023	0.0023	0.0026	0.0026	0.0023	0.0026	0.0026	0.0025	0.0029	0.0027	0.0028	1956	0.0299
1957	0.0029	0.0025	0.0026	0.0029	0.0029	0.0025	0.0033	0.0030	0.0031	0.0031	0.0029	0.0029	1957	0.0344

*Compound Annual Return

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Long-term Government Bonds: Income Returns
From 1926 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1958	0.0027	0.0025	0.0027	0.0026	0.0024	0.0027	0.0027	0.0027	0.0032	0.0032	0.0028	0.0033	1958	0.0327
1959	0.0031	0.0031	0.0035	0.0033	0.0033	0.0036	0.0035	0.0035	0.0034	0.0035	0.0035	0.0036	1959	0.0401
1960	0.0035	0.0037	0.0036	0.0032	0.0037	0.0034	0.0032	0.0034	0.0032	0.0033	0.0032	0.0033	1960	0.0426
1961	0.0033	0.0030	0.0031	0.0031	0.0034	0.0032	0.0033	0.0033	0.0032	0.0034	0.0032	0.0031	1961	0.0383
1962	0.0037	0.0032	0.0033	0.0033	0.0032	0.0030	0.0034	0.0034	0.0030	0.0035	0.0031	0.0032	1962	0.0400
1963	0.0032	0.0029	0.0031	0.0034	0.0033	0.0030	0.0036	0.0033	0.0034	0.0034	0.0032	0.0036	1963	0.0389
1964	0.0035	0.0032	0.0037	0.0035	0.0032	0.0038	0.0035	0.0035	0.0034	0.0034	0.0035	0.0035	1964	0.0415
1965	0.0033	0.0032	0.0038	0.0033	0.0033	0.0038	0.0034	0.0037	0.0035	0.0034	0.0037	0.0037	1965	0.0419
1966	0.0038	0.0034	0.0040	0.0036	0.0041	0.0039	0.0038	0.0043	0.0041	0.0040	0.0038	0.0039	1966	0.0449
1967	0.0040	0.0034	0.0039	0.0035	0.0043	0.0039	0.0043	0.0042	0.0040	0.0045	0.0045	0.0044	1967	0.0459
1968	0.0050	0.0042	0.0043	0.0049	0.0046	0.0042	0.0048	0.0042	0.0044	0.0045	0.0043	0.0049	1968	0.0550
1969	0.0050	0.0046	0.0047	0.0055	0.0047	0.0055	0.0052	0.0048	0.0055	0.0057	0.0049	0.0060	1969	0.0595
1970	0.0056	0.0052	0.0056	0.0054	0.0055	0.0064	0.0059	0.0057	0.0056	0.0055	0.0058	0.0053	1970	0.0674
1971	0.0051	0.0046	0.0056	0.0048	0.0047	0.0056	0.0052	0.0055	0.0050	0.0047	0.0051	0.0050	1971	0.0632
1972	0.0050	0.0047	0.0049	0.0048	0.0055	0.0049	0.0051	0.0049	0.0047	0.0052	0.0048	0.0045	1972	0.0587
1973	0.0054	0.0051	0.0056	0.0057	0.0058	0.0055	0.0061	0.0062	0.0055	0.0063	0.0056	0.0060	1973	0.0651
1974	0.0061	0.0055	0.0059	0.0068	0.0068	0.0061	0.0072	0.0065	0.0071	0.0070	0.0062	0.0067	1974	0.0727
1975	0.0068	0.0060	0.0066	0.0067	0.0067	0.0070	0.0068	0.0065	0.0073	0.0072	0.0061	0.0075	1975	0.0799
1976	0.0065	0.0061	0.0071	0.0064	0.0059	0.0073	0.0065	0.0069	0.0064	0.0061	0.0066	0.0063	1976	0.0789
1977	0.0059	0.0057	0.0065	0.0061	0.0067	0.0062	0.0059	0.0067	0.0061	0.0063	0.0063	0.0062	1977	0.0714
1978	0.0069	0.0060	0.0069	0.0063	0.0075	0.0069	0.0073	0.0070	0.0065	0.0073	0.0071	0.0068	1978	0.0790
1979	0.0079	0.0065	0.0074	0.0076	0.0077	0.0071	0.0076	0.0073	0.0068	0.0082	0.0083	0.0083	1979	0.0886
1980	0.0083	0.0084	0.0099	0.0100	0.0087	0.0086	0.0084	0.0081	0.0097	0.0097	0.0091	0.0108	1980	0.0997
1981	0.0094	0.0088	0.0111	0.0101	0.0104	0.0109	0.0109	0.0110	0.0114	0.0117	0.0113	0.0100	1981	0.1155
1982	0.0108	0.0103	0.0124	0.0112	0.0101	0.0120	0.0114	0.0112	0.0100	0.0091	0.0095	0.0093	1982	0.1350
1983	0.0087	0.0081	0.0089	0.0085	0.0091	0.0090	0.0088	0.0103	0.0096	0.0095	0.0094	0.0094	1983	0.1038
1984	0.0103	0.0092	0.0098	0.0104	0.0103	0.0106	0.0116	0.0106	0.0094	0.0108	0.0091	0.0098	1984	0.1174
1985	0.0096	0.0082	0.0094	0.0102	0.0097	0.0080	0.0094	0.0085	0.0088	0.0089	0.0081	0.0086	1985	0.1125
1986	0.0079	0.0073	0.0071	0.0063	0.0062	0.0070	0.0066	0.0063	0.0065	0.0069	0.0059	0.0070	1986	0.0898
1987	0.0064	0.0059	0.0066	0.0065	0.0066	0.0075	0.0073	0.0075	0.0075	0.0079	0.0075	0.0078	1987	0.0792
1988	0.0072	0.0071	0.0072	0.0070	0.0078	0.0076	0.0071	0.0083	0.0076	0.0076	0.0070	0.0075	1988	0.0897
1989	0.0080	0.0069	0.0079	0.0070	0.0080	0.0070	0.0068	0.0066	0.0065	0.0072	0.0064	0.0064	1989	0.0881

*Compound Annual Return

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Long-term Government Bonds: Income Returns
From 1926 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1990	0.0073	0.0066	0.0071	0.0075	0.0075	0.0068	0.0074	0.0071	0.0069	0.0081	0.0071	0.0072	1990	0.0819
1991	0.0071	0.0064	0.0064	0.0076	0.0068	0.0063	0.0076	0.0068	0.0068	0.0065	0.0060	0.0068	1991	0.0822
1992	0.0061	0.0059	0.0067	0.0065	0.0061	0.0067	0.0063	0.0060	0.0058	0.0057	0.0061	0.0063	1992	0.0726
1993	0.0059	0.0055	0.0063	0.0057	0.0052	0.0062	0.0054	0.0056	0.0050	0.0049	0.0053	0.0055	1993	0.0717
1994	0.0055	0.0049	0.0058	0.0057	0.0063	0.0061	0.0060	0.0066	0.0061	0.0066	0.0064	0.0066	1994	0.0659
1995	0.0070	0.0059	0.0064	0.0058	0.0065	0.0054	0.0056	0.0057	0.0052	0.0057	0.0051	0.0049	1995	0.0760
1996	0.0054	0.0048	0.0052	0.0059	0.0058	0.0054	0.0062	0.0057	0.0060	0.0058	0.0052	0.0056	1996	0.0618
1997	0.0056	0.0051	0.0059	0.0059	0.0058	0.0059	0.0058	0.0049	0.0058	0.0054	0.0047	0.0054	1997	0.0664
1998	0.0048	0.0044	0.0052	0.0049	0.0048	0.0052	0.0049	0.0048	0.0044	0.0042	0.0045	0.0045	1998	0.0583
1999	0.0042	0.0040	0.0053	0.0048	0.0045	0.0055	0.0051	0.0054	0.0052	0.0050	0.0056	0.0055	1999	0.0557
2000	0.0057	0.0051	0.0054	0.0047	0.0056	0.0052	0.0052	0.0050	0.0046	0.0053	0.0048	0.0045	2000	0.0650
2001	0.0049	0.0042	0.0045	0.0047	0.0050	0.0047	0.0052	0.0046	0.0041	0.0048	0.0041	0.0046	2001	0.0553
2002	0.0048	0.0043	0.0043	0.0054	0.0049	0.0044	0.0051	0.0044	0.0042	0.0040	0.0040	0.0045	2002	0.0559
2003	0.0041	0.0038	0.0040	0.0040	0.0039	0.0036	0.0038	0.0042	0.0046	0.0041	0.0039	0.0047	2003	0.0480
2004	0.0042	0.0038	0.0043	0.0039	0.0040	0.0048	0.0043	0.0045	0.0040	0.0038	0.0041	0.0043	2004	0.0502
2005	0.0041	0.0035	0.0041	0.0039	0.0040	0.0036	0.0034	0.0040	0.0035	0.0039	0.0039	0.0039	2005	0.0469
2006	0.0040	0.0036	0.0039	0.0039	0.0048	0.0044	0.0045	0.0043	0.0039	0.0042	0.0039	0.0036	2006	0.0468
2007	0.0043	0.0038	0.0039	0.0042	0.0041	0.0040	0.0046	0.0042	0.0037	0.0043	0.0039	0.0037	2007	0.0486
2008	0.0040	0.0034	0.0037	0.0035	0.0037	0.0040	0.0039	0.0036	0.0039	0.0037	0.0036	0.0033	2008	0.0445
2009	0.0024	0.0030	0.0035	0.0029	0.0033	0.0038	0.0036	0.0036	0.0034	0.0033	0.0035	0.0034	2009	0.0347
2010	0.0036	0.0033	0.0040	0.0038	0.0034	0.0037	0.0031	0.0032	0.0026	0.0027	0.0032	0.0032	2010	0.0425
2011	0.0035	0.0032	0.0036	0.0034	0.0036	0.0032	0.0032	0.0034	0.0026	0.0022	0.0024	0.0022	2011	0.0382
2012	0.0022	0.0020	0.0022	0.0025	0.0023	0.0018	0.0020	0.0018	0.0017	0.0021	0.0019	0.0019	2012	0.0247
2013	0.0022	0.0022	0.0022	0.0026	0.0023	0.0024	0.0030	0.0028	0.0029	0.0029	0.0027	0.0031	2013	0.0290
2014	0.0032	0.0026	0.0029	0.0028	0.0028	0.0025	0.0027	0.0026	0.0023	0.0025	0.0023	0.0022	2014	0.0341
2015	0.0020	0.0015	0.0021	0.0019	0.0020	0.0023	0.0024	0.0022	0.0021	0.0021	0.0022	0.0022	2015	0.0247
2016	0.0021	0.0020	0.0018	0.0017	0.0020	0.0018	0.0014	0.0016	0.0015	0.0016	0.0018	0.0022	2016	0.0230
2017	0.0024	0.0021	0.0023	0.0021	0.0024	0.0021	0.0022	0.0022	0.0019	0.0022	0.0021	0.0020	2017	0.0267
2018	0.0024	0.0022	0.0024	0.0025	0.0025	0.0023	0.0025	0.0025	0.0022	0.0030	0.0028	0.0027	2018	0.0282
2019	0.0025	0.0022	0.0023	0.0023	0.0023	0.0018	0.0021	0.0019	0.0015	0.0016	0.0016	0.0018	2019	0.0255
2020	0.0020	0.0015	0.0013	0.0009	0.0009	0.0009	0.0010	0.0008	0.0010	0.0009	0.0011	0.0011	2020	0.0153
2021	0.0011	0.0012	0.0018	0.0019	0.0018	0.0017	0.0016	0.0015	0.0014	0.0015	0.0017	0.0015	2021	0.0173

*Compound Annual Return

MODERN REGULATORY FINANCE

ROGER A. MORIN, PhD

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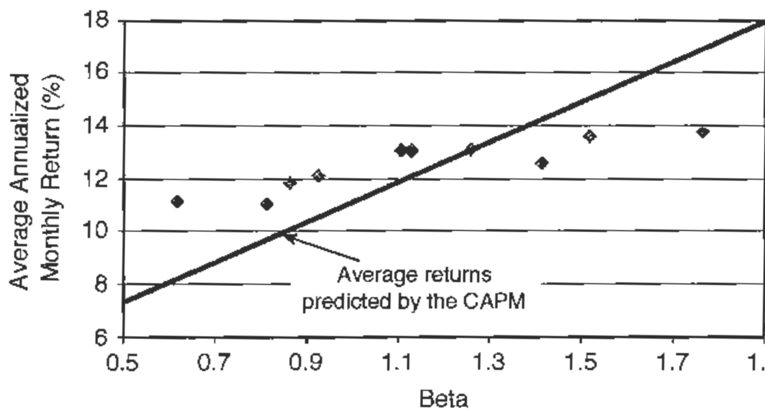
on low-beta stocks are higher than predicted by the CAPM, and realized returns on high-beta stocks are lower than predicted by the CAPM. Stocks with the lowest beta estimates had average returns of 11.1% per year, but the CAPM says the expected return was 8.3% per year. Stocks with the highest beta estimates had average returns of 13.7% per year, but the CAPM says the expected return was 16.8% per year.

Figure 7-1

Average Returns vs Beta Over An Extended Time Period (1928-2003)



Brealey, Myers, and Allen (2017), among many others,[9] provide more recent empirical evidence very similar to the relationship depicted in Figure 7-1. In fact, Brealey, Myers and Allen (2017) extend previous analyses to the end of 2014, and provide a similar chart to that presented by Fama and French (2004). The upward-sloping line on Figure 7-1 represents the relationship between beta and return that is implied by the CAPM and each dot represents the observed return for a particular portfolio. Clearly, the low-beta portfolios still earn higher returns than the CAPM would imply. Goyal (2011) also found a security market line flatter than that predicted by the CAPM.[10] With few exceptions, the empirical studies agree that the implied intercept term exceeds the risk-free rate and the slope term is less than predicted by the CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. This is one of the most well-known results in finance, and is particularly pertinent for public utilities whose betas are typically less than 1.00.

9. For a summary of the empirical evidence on the CAPM, see Jensen (1972) and Ross (1978). The major empirical tests of the CAPM were published by Friend and Blume (1975), Black, Jensen, and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973), Blume and Husic (1973), Fama and Macbeth (1972), Basu (1977), Reinganum (1981B), Litzenberger and Ramaswamy (1979), Banz (1981), Gibbons (1982), Stambaugh (1982), Shanken (1985), Black (1993), and Brealey, Myers, and Allen (2017). Evidence in the Canadian context is available in Morin (1980, 1981).

10. Goyal, Amit, "Empirical Cross-Sectional Asset Pricing: A Survey," Swiss Society for Financial Market Research, 2011. Published online: December 2011.

constant $\dot{\alpha}$, which must be estimated econometrically from market data.[21] Table 7-3 drawn from Villadsen, Vilbert, et. al. (2017) summarizes the empirical evidence on the magnitude of alpha.[22]

For an alpha in the range of 1% – 2% and for reasonable values of the MRP and the risk-free rate, Equation 7-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,b(R_M - R_F) \qquad (7\text{-}6)$$

Using reasonable data inputs for the risk-free rate and the MRP, Equation 7-6 produces results that are indistinguishable from the ECAPM of Equation 7-5.[23]

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment.

21. The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, bnt they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities gronped into portfolios, are related to their corresponding betas by statistical regression techniques; that is, Equation 6-4 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their results demonstrate how the standard CAPM underestimates the cost of equity of pnblic utilities because of ntilities' high dividend yield and return skewness.

22. Table 7-3 is drawn from Villadsen, B., Vilbert, M. J., Harris, D., and Kolbe, A. L., "Risk and Return for Regulated Industries," The Brattle Group, Elsevier Academic Press, 2017.

23. Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926-1984 was given by:

$$\text{Return} = 0.0829 + 0.0520$$

Given that the risk-free rate over the estimation period was approximately 6% and that the MRP was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x\,(R_M - R_F) + (1 - x)\,b(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,b(R_M - R_F)$$

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The Capital Asset Pricing Model: Theory and Evidence

Eugene F. Fama and Kenneth R. French

The capital asset pricing model (CAPM) of William Sharpe (1964) and John Lintner (1965) marks the birth of asset pricing theory (resulting in a Nobel Prize for Sharpe in 1990). Four decades later, the CAPM is still widely used in applications, such as estimating the cost of capital for firms and evaluating the performance of managed portfolios. It is the centerpiece of MBA investment courses. Indeed, it is often the only asset pricing model taught in these courses.[1]

The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor—poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive "market portfolio" that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it

[1] Although every asset pricing model is a capital asset pricing model, the finance profession reserves the acronym CAPM for the specific model of Sharpe (1964), Lintner (1965) and Black (1972) discussed here. Thus, throughout the paper we refer to the Sharpe-Lintner-Black model as the CAPM.

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legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

We begin by outlining the logic of the CAPM, focusing on its predictions about risk and expected return. We then review the history of empirical work and what it says about shortcomings of the CAPM that pose challenges to be explained by alternative models.

The Logic of the CAPM

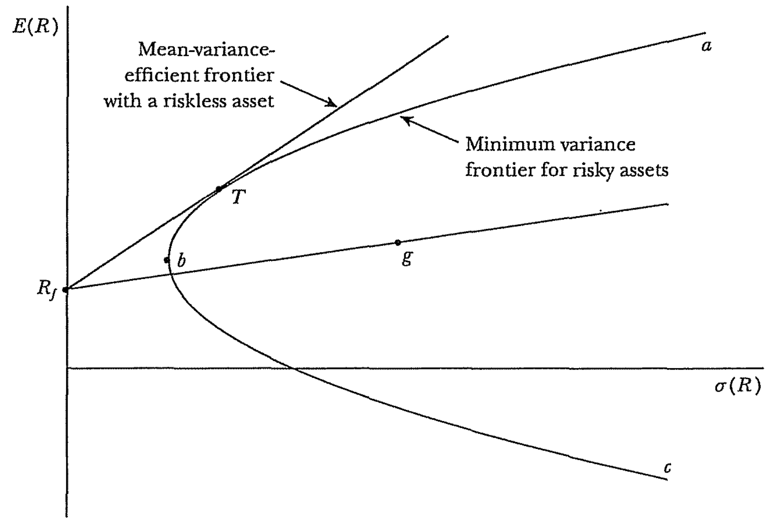
The CAPM builds on the model of portfolio choice developed by Harry Markowitz (1959). In Markowitz's model, an investor selects a portfolio at time $t - 1$ that produces a stochastic return at t. The model assumes investors are risk averse and, when choosing among portfolios, they care only about the mean and variance of their one-period investment return. As a result, investors choose "mean-variance-efficient" portfolios, in the sense that the portfolios 1) minimize the variance of portfolio return, given expected return, and 2) maximize expected return, given variance. Thus, the Markowitz approach is often called a "mean-variance model."

The portfolio model provides an algebraic condition on asset weights in mean-variance-efficient portfolios. The CAPM turns this algebraic statement into a testable prediction about the relation between risk and expected return by identifying a portfolio that must be efficient if asset prices are to clear the market of all assets.

Sharpe (1964) and Lintner (1965) add two key assumptions to the Markowitz model to identify a portfolio that must be mean-variance-efficient. The first assumption is *complete agreement*: given market clearing asset prices at $t - 1$, investors agree on the joint distribution of asset returns from $t - 1$ to t. And this distribution is the true one—that is, it is the distribution from which the returns we use to test the model are drawn. The second assumption is that there is *borrowing and lending at a risk-free rate*, which is the same for all investors and does not depend on the amount borrowed or lent.

Figure 1 describes portfolio opportunities and tells the CAPM story. The horizontal axis shows portfolio risk, measured by the standard deviation of portfolio return; the vertical axis shows expected return. The curve *abc*, which is called the minimum variance frontier, traces combinations of expected return and risk for portfolios of risky assets that minimize return variance at different levels of expected return. (These portfolios do not include risk-free borrowing and lending.) The tradeoff between risk and expected return for minimum variance portfolios is apparent. For example, an investor who wants a high expected return, perhaps at point *a*, must accept high volatility. At point *T*, the investor can have an interme-

Figure 1
Investment Opportunities



diate expected return with lower volatility. If there is no risk-free borrowing or lending, only portfolios above b along abc are mean-variance-efficient, since these portfolios also maximize expected return, given their return variances.

Adding risk-free borrowing and lending turns the efficient set into a straight line. Consider a portfolio that invests the proportion x of portfolio funds in a risk-free security and $1 - x$ in some portfolio g. If all funds are invested in the risk-free security—that is, they are loaned at the risk-free rate of interest—the result is the point R_f in Figure 1, a portfolio with zero variance and a risk-free rate of return. Combinations of risk-free lending and positive investment in g plot on the straight line between R_f and g. Points to the right of g on the line represent borrowing at the risk-free rate, with the proceeds from the borrowing used to increase investment in portfolio g. In short, portfolios that combine risk-free lending or borrowing with some risky portfolio g plot along a straight line from R_f through g in Figure 1.[2]

[2] Formally, the return, expected return and standard deviation of return on portfolios of the risk-free asset f and a risky portfolio g vary with x, the proportion of portfolio funds invested in f, as

$$R_p = xR_f + (1 - x)R_g,$$

$$E(R_p) = xR_f + (1 - x)E(R_g),$$

$$\sigma(R_p) = (1 - x)\sigma(R_g),\ x \leq 1.0,$$

which together imply that the portfolios plot along the line from R_f through g in Figure 1.

To obtain the mean-variance-efficient portfolios available with risk-free borrowing and lending, one swings a line from R_f in Figure 1 up and to the left as far as possible, to the tangency portfolio T. We can then see that all efficient portfolios are combinations of the risk-free asset (either risk-free borrowing or lending) and a single risky tangency portfolio, T. This key result is Tobin's (1958) "separation theorem."

The punch line of the CAPM is now straightforward. With complete agreement about distributions of returns, all investors see the same opportunity set (Figure 1), and they combine the same risky tangency portfolio T with risk-free lending or borrowing. Since all investors hold the same portfolio T of risky assets, it must be the value-weight market portfolio of risky assets. Specifically, each risky asset's weight in the tangency portfolio, which we now call M (for the "market"), must be the total market value of all outstanding units of the asset divided by the total market value of all risky assets. In addition, the risk-free rate must be set (along with the prices of risky assets) to clear the market for risk-free borrowing and lending.

In short, the CAPM assumptions imply that the market portfolio M must be on the minimum variance frontier if the asset market is to clear. This means that the algebraic relation that holds for any minimum variance portfolio must hold for the market portfolio. Specifically, if there are N risky assets,

$$\text{(Minimum Variance Condition for } M) \quad E(R_i) = E(R_{ZM}) + [E(R_M) - E(R_{ZM})]\beta_{iM}, \; i = 1, \ldots, N.$$

In this equation, $E(R_i)$ is the expected return on asset i, and β_{iM}, the market beta of asset i, is the covariance of its return with the market return divided by the variance of the market return,

$$\text{(Market Beta)} \quad \beta_{iM} = \frac{\text{cov}(R_i, R_M)}{\sigma^2(R_M)}.$$

The first term on the right-hand side of the minimum variance condition, $E(R_{ZM})$, is the expected return on assets that have market betas equal to zero, which means their returns are uncorrelated with the market return. The second term is a risk premium—the market beta of asset i, β_{iM}, times the premium per unit of beta, which is the expected market return, $E(R_M)$, minus $E(R_{ZM})$.

Since the market beta of asset i is also the slope in the regression of its return on the market return, a common (and correct) interpretation of beta is that it measures the sensitivity of the asset's return to variation in the market return. But there is another interpretation of beta more in line with the spirit of the portfolio model that underlies the CAPM. The risk of the market portfolio, as measured by the variance of its return (the denominator of β_{iM}), is a weighted average of the covariance risks of the assets in M (the numerators of β_{iM} for different assets).

Thus, β_{iM} is the covariance risk of asset i in M measured relative to the average covariance risk of assets, which is just the variance of the market return.[3] In economic terms, β_{iM} is proportional to the risk each dollar invested in asset i contributes to the market portfolio.

The last step in the development of the Sharpe-Lintner model is to use the assumption of risk-free borrowing and lending to nail down $E(R_{ZM})$, the expected return on zero-beta assets. A risky asset's return is uncorrelated with the market return—its beta is zero—when the average of the asset's covariances with the returns on other assets just offsets the variance of the asset's return. Such a risky asset is riskless in the market portfolio in the sense that it contributes nothing to the variance of the market return.

When there is risk-free borrowing and lending, the expected return on assets that are uncorrelated with the market return, $E(R_{ZM})$, must equal the risk-free rate, R_f. The relation between expected return and beta then becomes the familiar Sharpe-Lintner CAPM equation,

$$\text{(Sharpe-Lintner CAPM)} \quad E(R_i) = R_f + [E(R_M) - R_f]\beta_{iM}, \; i = 1, \ldots, N.$$

In words, the expected return on any asset i is the risk-free interest rate, R_f, plus a risk premium, which is the asset's market beta, β_{iM}, times the premium per unit of beta risk, $E(R_M) - R_f$.

Unrestricted risk-free borrowing and lending is an unrealistic assumption. Fischer Black (1972) develops a version of the CAPM without risk-free borrowing or lending. He shows that the CAPM's key result—that the market portfolio is mean-variance-efficient—can be obtained by instead allowing unrestricted short sales of risky assets. In brief, back in Figure 1, if there is no risk-free asset, investors select portfolios from along the mean-variance-efficient frontier from a to b. Market clearing prices imply that when one weights the efficient portfolios chosen by investors by their (positive) shares of aggregate invested wealth, the resulting portfolio is the market portfolio. The market portfolio is thus a portfolio of the efficient portfolios chosen by investors. With unrestricted short selling of risky assets, portfolios made up of efficient portfolios are themselves efficient. Thus, the market portfolio is efficient, which means that the minimum variance condition for M given above holds, and it is the expected return-risk relation of the Black CAPM.

The relations between expected return and market beta of the Black and Sharpe-Lintner versions of the CAPM differ only in terms of what each says about $E(R_{ZM})$, the expected return on assets uncorrelated with the market. The Black version says only that $E(R_{ZM})$ must be less than the expected market return, so the

[3] Formally, if x_{iM} is the weight of asset i in the market portfolio, then the variance of the portfolio's return is

$$\sigma^2(R_M) = Cov(R_M, R_M) = Cov\left(\sum_{i=1}^{N} x_{iM}R_i, R_M\right) = \sum_{i=1}^{N} x_{iM}Cov(R_i, R_M).$$

premium for beta is positive. In contrast, in the Sharpe-Lintner version of the model, $E(R_{ZM})$ must be the risk-free interest rate, R_f, and the premium per unit of beta risk is $E(R_M) - R_f$.

The assumption that short selling is unrestricted is as unrealistic as unrestricted risk-free borrowing and lending. If there is no risk-free asset and short sales of risky assets are not allowed, mean-variance investors still choose efficient portfolios—points above *b* on the *abc* curve in Figure 1. But when there is no short selling of risky assets and no risk-free asset, the algebra of portfolio efficiency says that portfolios made up of efficient portfolios are not typically efficient. This means that the market portfolio, which is a portfolio of the efficient portfolios chosen by investors, is not typically efficient. And the CAPM relation between expected return and market beta is lost. This does not rule out predictions about expected return and betas with respect to other efficient portfolios—if theory can specify portfolios that must be efficient if the market is to clear. But so far this has proven impossible.

In short, the familiar CAPM equation relating expected asset returns to their market betas is just an application to the market portfolio of the relation between expected return and portfolio beta that holds in any mean-variance-efficient portfolio. The efficiency of the market portfolio is based on many unrealistic assumptions, including complete agreement and either unrestricted risk-free borrowing and lending or unrestricted short selling of risky assets. But all interesting models involve unrealistic simplifications, which is why they must be tested against data.

Early Empirical Tests

Tests of the CAPM are based on three implications of the relation between expected return and market beta implied by the model. First, expected returns on all assets are linearly related to their betas, and no other variable has marginal explanatory power. Second, the beta premium is positive, meaning that the expected return on the market portfolio exceeds the expected return on assets whose returns are uncorrelated with the market return. Third, in the Sharpe-Lintner version of the model, assets uncorrelated with the market have expected returns equal to the risk-free interest rate, and the beta premium is the expected market return minus the risk-free rate. Most tests of these predictions use either cross-section or time-series regressions. Both approaches date to early tests of the model.

Tests on Risk Premiums

The early cross-section regression tests focus on the Sharpe-Lintner model's predictions about the intercept and slope in the relation between expected return and market beta. The approach is to regress a cross-section of average asset returns on estimates of asset betas. The model predicts that the intercept in these regressions is the risk-free interest rate, R_f, and the coefficient on beta is the expected return on the market in excess of the risk-free rate, $E(R_M) - R_f$.

Two problems in these tests quickly became apparent. First, estimates of beta for individual assets are imprecise, creating a measurement error problem when they are used to explain average returns. Second, the regression residuals have common sources of variation, such as industry effects in average returns. Positive correlation in the residuals produces downward bias in the usual ordinary least squares estimates of the standard errors of the cross-section regression slopes.

To improve the precision of estimated betas, researchers such as Blume (1970), Friend and Blume (1970) and Black, Jensen and Scholes (1972) work with portfolios, rather than individual securities. Since expected returns and market betas combine in the same way in portfolios, if the CAPM explains security returns it also explains portfolio returns.[4] Estimates of beta for diversified portfolios are more precise than estimates for individual securities. Thus, using portfolios in cross-section regressions of average returns on betas reduces the critical errors in variables problem. Grouping, however, shrinks the range of betas and reduces statistical power. To mitigate this problem, researchers sort securities on beta when forming portfolios; the first portfolio contains securities with the lowest betas, and so on, up to the last portfolio with the highest beta assets. This sorting procedure is now standard in empirical tests.

Fama and MacBeth (1973) propose a method for addressing the inference problem caused by correlation of the residuals in cross-section regressions. Instead of estimating a single cross-section regression of average monthly returns on betas, they estimate month-by-month cross-section regressions of monthly returns on betas. The times-series means of the monthly slopes and intercepts, along with the standard errors of the means, are then used to test whether the average premium for beta is positive and whether the average return on assets uncorrelated with the market is equal to the average risk-free interest rate. In this approach, the standard errors of the average intercept and slope are determined by the month-to-month variation in the regression coefficients, which fully captures the effects of residual correlation on variation in the regression coefficients, but sidesteps the problem of actually estimating the correlations. The residual correlations are, in effect, captured via repeated sampling of the regression coefficients. This approach also becomes standard in the literature.

Jensen (1968) was the first to note that the Sharpe-Lintner version of the

[4] Formally, if x_{ip}, $i = 1, \ldots, N$, are the weights for assets in some portfolio p, the expected return and market beta for the portfolio are related to the expected returns and betas of assets as

$$E(R_p) = \sum_{i=1}^{N} x_{ip}E(R_i), \text{ and } \beta_{pM} = \sum_{i=1}^{N} x_{ip}\beta_{pM}.$$

Thus, the CAPM relation between expected return and beta,

$$E(R_i) = E(R_f) + [E(R_M) - E(R_f)]\beta_{iM},$$

holds when asset i is a portfolio, as well as when i is an individual security.

relation between expected return and market beta also implies a time-series regression test. The Sharpe-Lintner CAPM says that the expected value of an asset's excess return (the asset's return minus the risk-free interest rate, $R_{it} - R_{ft}$) is completely explained by its expected CAPM risk premium (its beta times the expected value of $R_{Mt} - R_{ft}$). This implies that "Jensen's alpha," the intercept term in the time-series regression,

$$\text{(Time-Series Regression)} \quad R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \varepsilon_{it},$$

is zero for each asset.

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too "flat." Recall that, in cross-section regressions, the Sharpe-Lintner model predicts that the intercept is the risk-free rate and the coefficient on beta is the expected market return in excess of the risk-free rate, $E(R_M) - R_f$. The regressions consistently find that the intercept is greater than the average risk-free rate (typically proxied as the return on a one-month Treasury bill), and the coefficient on beta is less than the average excess market return (proxied as the average return on a portfolio of U.S. common stocks minus the Treasury bill rate). This is true in the early tests, such as Douglas (1968), Black, Jensen and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973) and Fama and MacBeth (1973), as well as in more recent cross-section regression tests, like Fama and French (1992).

The evidence that the relation between beta and average return is too flat is confirmed in time-series tests, such as Friend and Blume (1970), Black, Jensen and Scholes (1972) and Stambaugh (1982). The intercepts in time-series regressions of excess asset returns on the excess market return are positive for assets with low betas and negative for assets with high betas.

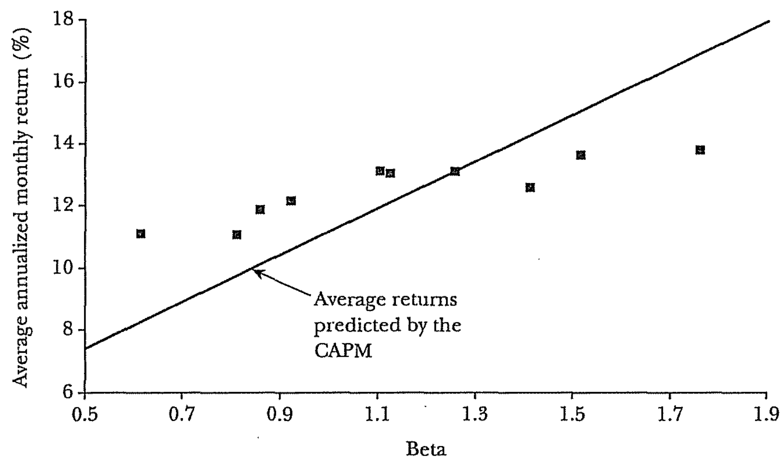
Figure 2 provides an updated example of the evidence. In December of each year, we estimate a preranking beta for every NYSE (1928–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stock in the CRSP (Center for Research in Security Prices of the University of Chicago) database, using two to five years (as available) of prior monthly returns.[5] We then form ten value-weight portfolios based on these preranking betas and compute their returns for the next twelve months. We repeat this process for each year from 1928 to 2003. The result is 912 monthly returns on ten beta-sorted portfolios. Figure 2 plots each portfolio's average return against its postranking beta, estimated by regressing its monthly returns for 1928–2003 on the return on the CRSP value-weight portfolio of U.S. common stocks.

The Sharpe-Lintner CAPM predicts that the portfolios plot along a straight

[5] To be included in the sample for year t, a security must have market equity data (price times shares outstanding) for December of $t - 1$, and CRSP must classify it as ordinary common equity. Thus, we exclude securities such as American Depository Receipts (ADRs) and Real Estate Investment Trusts (REITs).

Figure 2

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



line, with an intercept equal to the risk-free rate, R_f, and a slope equal to the expected excess return on the market, $E(R_M) - R_f$. We use the average one-month Treasury bill rate and the average excess CRSP market return for 1928–2003 to estimate the predicted line in Figure 2. Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Lintner CAPM predicts. The returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.

Although the observed premium per unit of beta is lower than the Sharpe-Lintner model predicts, the relation between average return and beta in Figure 2 is roughly linear. This is consistent with the Black version of the CAPM, which predicts only that the beta premium is positive. Even this less restrictive model, however, eventually succumbs to the data.

Testing Whether Market Betas Explain Expected Returns

The Sharpe-Lintner and Black versions of the CAPM share the prediction that the market portfolio is mean-variance-efficient. This implies that differences in expected return across securities and portfolios are entirely explained by differences in market beta; other variables should add nothing to the explanation of expected return. This prediction plays a prominent role in tests of the CAPM. In the early work, the weapon of choice is cross-section regressions.

In the framework of Fama and MacBeth (1973), one simply adds predetermined explanatory variables to the month-by-month cross-section regressions of returns on beta. If all differences in expected return are explained by beta, the average slopes on the additional variables should not be reliably different from zero. Clearly, the trick in the cross-section regression approach is to choose specific additional variables likely to expose any problems of the CAPM prediction that, because the market portfolio is efficient, market betas suffice to explain expected asset returns.

For example, in Fama and MacBeth (1973) the additional variables are squared market betas (to test the prediction that the relation between expected return and beta is linear) and residual variances from regressions of returns on the market return (to test the prediction that market beta is the only measure of risk needed to explain expected returns). These variables do not add to the explanation of average returns provided by beta. Thus, the results of Fama and MacBeth (1973) are consistent with the hypothesis that their market proxy—an equal-weight portfolio of NYSE stocks—is on the minimum variance frontier.

The hypothesis that market betas completely explain expected returns can also be tested using time-series regressions. In the time-series regression described above (the excess return on asset i regressed on the excess market return), the intercept is the difference between the asset's average excess return and the excess return predicted by the Sharpe-Lintner model, that is, beta times the average excess market return. If the model holds, there is no way to group assets into portfolios whose intercepts are reliably different from zero. For example, the intercepts for a portfolio of stocks with high ratios of earnings to price and a portfolio of stocks with low earning-price ratios should both be zero. Thus, to test the hypothesis that market betas suffice to explain expected returns, one estimates the time-series regression for a set of assets (or portfolios) and then jointly tests the vector of regression intercepts against zero. The trick in this approach is to choose the left-hand-side assets (or portfolios) in a way likely to expose any shortcoming of the CAPM prediction that market betas suffice to explain expected asset returns.

In early applications, researchers use a variety of tests to determine whether the intercepts in a set of time-series regressions are all zero. The tests have the same asymptotic properties, but there is controversy about which has the best small sample properties. Gibbons, Ross and Shanken (1989) settle the debate by providing an F-test on the intercepts that has exact small-sample properties. They also show that the test has a simple economic interpretation. In effect, the test constructs a candidate for the tangency portfolio T in Figure 1 by optimally combining the market proxy and the left-hand-side assets of the time-series regressions. The estimator then tests whether the efficient set provided by the combination of this tangency portfolio and the risk-free asset is reliably superior to the one obtained by combining the risk-free asset with the market proxy alone. In other words, the Gibbons, Ross and Shanken statistic tests whether the market proxy is the tangency portfolio in the set of portfolios that can be constructed by combining the market portfolio with the specific assets used as dependent variables in the time-series regressions.

Enlightened by this insight of Gibbons, Ross and Shanken (1989), one can see a similar interpretation of the cross-section regression test of whether market betas suffice to explain expected returns. In this case, the test is whether the additional explanatory variables in a cross-section regression identify patterns in the returns on the left-hand-side assets that are not explained by the assets' market betas. This amounts to testing whether the market proxy is on the minimum variance frontier that can be constructed using the market proxy and the left-hand-side assets included in the tests.

An important lesson from this discussion is that time-series and cross-section regressions do not, strictly speaking, test the CAPM. What is literally tested is whether a specific proxy for the market portfolio (typically a portfolio of U.S. common stocks) is efficient in the set of portfolios that can be constructed from it and the left-hand-side assets used in the test. One might conclude from this that the CAPM has never been tested, and prospects for testing it are not good because 1) the set of left-hand-side assets does not include all marketable assets, and 2) data for the true market portfolio of all assets are likely beyond reach (Roll, 1977; more on this later). But this criticism can be leveled at tests of any economic model when the tests are less than exhaustive or when they use proxies for the variables called for by the model.

The bottom line from the early cross-section regression tests of the CAPM, such as Fama and MacBeth (1973), and the early time-series regression tests, like Gibbons (1982) and Stambaugh (1982), is that standard market proxies seem to be on the minimum variance frontier. That is, the central predictions of the Black version of the CAPM, that market betas suffice to explain expected returns and that the risk premium for beta is positive, seem to hold. But the more specific prediction of the Sharpe-Lintner CAPM that the premium per unit of beta is the expected market return minus the risk-free interest rate is consistently rejected.

The success of the Black version of the CAPM in early tests produced a consensus that the model is a good description of expected returns. These early results, coupled with the model's simplicity and intuitive appeal, pushed the CAPM to the forefront of finance.

Recent Tests

Starting in the late 1970s, empirical work appears that challenges even the Black version of the CAPM. Specifically, evidence mounts that much of the variation in expected return is unrelated to market beta.

The first blow is Basu's (1977) evidence that when common stocks are sorted on earnings-price ratios, future returns on high E/P stocks are higher than predicted by the CAPM. Banz (1981) documents a size effect: when stocks are sorted on market capitalization (price times shares outstanding), average returns on small stocks are higher than predicted by the CAPM. Bhandari (1988) finds that high debt-equity ratios (book value of debt over the market value of equity, a measure of leverage) are associated with returns that are too high relative to their market betas.

Finally, Statman (1980) and Rosenberg, Reid and Lanstein (1985) document that stocks with high book-to-market equity ratios (B/M, the ratio of the book value of a common stock to its market value) have high average returns that are not captured by their betas.

There is a theme in the contradictions of the CAPM summarized above. Ratios involving stock prices have information about expected returns missed by market betas. On reflection, this is not surprising. A stock's price depends not only on the expected cash flows it will provide, but also on the expected returns that discount expected cash flows back to the present. Thus, in principle, the cross-section of prices has information about the cross-section of expected returns. (A high expected return implies a high discount rate and a low price.) The cross-section of stock prices is, however, arbitrarily affected by differences in scale (or units). But with a judicious choice of scaling variable X, the ratio X/P can reveal differences in the cross-section of expected stock returns. Such ratios are thus prime candidates to expose shortcomings of asset pricing models—in the case of the CAPM, shortcomings of the prediction that market betas suffice to explain expected returns (Ball, 1978). The contradictions of the CAPM summarized above suggest that earnings-price, debt-equity and book-to-market ratios indeed play this role.

Fama and French (1992) update and synthesize the evidence on the empirical failures of the CAPM. Using the cross-section regression approach, they confirm that size, earnings-price, debt-equity and book-to-market ratios add to the explanation of expected stock returns provided by market beta. Fama and French (1996) reach the same conclusion using the time-series regression approach applied to portfolios of stocks sorted on price ratios. They also find that different price ratios have much the same information about expected returns. This is not surprising given that price is the common driving force in the price ratios, and the numerators are just scaling variables used to extract the information in price about expected returns.

Fama and French (1992) also confirm the evidence (Reinganum, 1981; Stambaugh, 1982; Lakonishok and Shapiro, 1986) that the relation between average return and beta for common stocks is even flatter after the sample periods used in the early empirical work on the CAPM. The estimate of the beta premium is, however, clouded by statistical uncertainty (a large standard error). Kothari, Shanken and Sloan (1995) try to resuscitate the Sharpe-Lintner CAPM by arguing that the weak relation between average return and beta is just a chance result. But the strong evidence that other variables capture variation in expected return missed by beta makes this argument irrelevant. If betas do not suffice to explain expected returns, the market portfolio is not efficient, and the CAPM is dead in its tracks. Evidence on the size of the market premium can neither save the model nor further doom it.

The synthesis of the evidence on the empirical problems of the CAPM provided by Fama and French (1992) serves as a catalyst, marking the point when it is generally acknowledged that the CAPM has potentially fatal problems. Research then turns to explanations.

One possibility is that the CAPM's problems are spurious, the result of data dredging—publication-hungry researchers scouring the data and unearthing contradictions that occur in specific samples as a result of chance. A standard response to this concern is to test for similar findings in other samples. Chan, Hamao and Lakonishok (1991) find a strong relation between book-to-market equity (B/M) and average return for Japanese stocks. Capaul, Rowley and Sharpe (1993) observe a similar B/M effect in four European stock markets and in Japan. Fama and French (1998) find that the price ratios that produce problems for the CAPM in U.S. data show up in the same way in the stock returns of twelve non-U.S. major markets, and they are present in emerging market returns. This evidence suggests that the contradictions of the CAPM associated with price ratios are not sample specific.

Explanations: Irrational Pricing or Risk

Among those who conclude that the empirical failures of the CAPM are fatal, two stories emerge. On one side are the behavioralists. Their view is based on evidence that stocks with high ratios of book value to market price are typically firms that have fallen on bad times, while low B/M is associated with growth firms (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1995). The behavioralists argue that sorting firms on book-to-market ratios exposes investor overreaction to good and bad times. Investors overextrapolate past performance, resulting in stock prices that are too high for growth (low B/M) firms and too low for distressed (high B/M, so-called value) firms. When the overreaction is eventually corrected, the result is high returns for value stocks and low returns for growth stocks. Proponents of this view include DeBondt and Thaler (1987), Lakonishok, Shleifer and Vishny (1994) and Haugen (1995).

The second story for explaining the empirical contradictions of the CAPM is that they point to the need for a more complicated asset pricing model. The CAPM is based on many unrealistic assumptions. For example, the assumption that investors care only about the mean and variance of one-period portfolio returns is extreme. It is reasonable that investors also care about how their portfolio return covaries with labor income and future investment opportunities, so a portfolio's return variance misses important dimensions of risk. If so, market beta is not a complete description of an asset's risk, and we should not be surprised to find that differences in expected return are not completely explained by differences in beta. In this view, the search should turn to asset pricing models that do a better job explaining average returns.

Merton's (1973) intertemporal capital asset pricing model (ICAPM) is a natural extension of the CAPM. The ICAPM begins with a different assumption about investor objectives. In the CAPM, investors care only about the wealth their portfolio produces at the end of the current period. In the ICAPM, investors are concerned not only with their end-of-period payoff, but also with the opportunities they will have to consume or invest the payoff. Thus, when choosing a portfolio at time $t - 1$, ICAPM investors consider how their wealth at t might vary with future *state variables,* including labor income, the prices of consumption goods and the nature of portfolio opportunities at t, and expectations about the labor income, consumption and investment opportunities to be available after t.

Like CAPM investors, ICAPM investors prefer high expected return and low return variance. But ICAPM investors are also concerned with the covariances of portfolio returns with state variables. As a result, optimal portfolios are "multifactor efficient," which means they have the largest possible expected returns, given their return variances and the covariances of their returns with the relevant state variables.

Fama (1996) shows that the ICAPM generalizes the logic of the CAPM. That is, if there is risk-free borrowing and lending or if short sales of risky assets are allowed, market clearing prices imply that the market portfolio is multifactor efficient. Moreover, multifactor efficiency implies a relation between expected return and beta risks, but it requires additional betas, along with a market beta, to explain expected returns.

An ideal implementation of the ICAPM would specify the state variables that affect expected returns. Fama and French (1993) take a more indirect approach, perhaps more in the spirit of Ross's (1976) arbitrage pricing theory. They argue that though size and book-to-market equity are not themselves state variables, the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns that are not captured by the market return and are priced separately from market betas. In support of this claim, they show that the returns on the stocks of small firms covary more with one another than with returns on the stocks of large firms, and returns on high book-to-market (value) stocks covary more with one another than with returns on low book-to-market (growth) stocks. Fama and French (1995) show that there are similar size and book-to-market patterns in the covariation of fundamentals like earnings and sales.

Based on this evidence, Fama and French (1993, 1996) propose a three-factor model for expected returns,

$$\text{(Three-Factor Model)} \quad E(R_{it}) - R_{ft} = \beta_{iM}[E(R_{Mt}) - R_{ft}] + \beta_{is}E(SMB_t) + \beta_{ih}E(HML_t).$$

In this equation, SMB_t (small minus big) is the difference between the returns on diversified portfolios of small and big stocks, HML_t (high minus low) is the difference between the returns on diversified portfolios of high and low B/M stocks, and the betas are slopes in the multiple regression of $R_{it} - R_{ft}$ on $R_{Mt} - R_{ft}$, SMB_t and HML_t.

For perspective, the average value of the market premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, which is 3.5 standard errors from zero. The average values of SMB_t, and HML_t are 3.6 percent and 5.0 percent per year, and they are 2.1 and 3.1 standard errors from zero. All three premiums are volatile, with annual standard deviations of 21.0 percent ($R_{Mt} - R_{ft}$), 14.6 percent (SMB_t) and 14.2 percent (HML_t) per year. Although the average values of the premiums are large, high volatility implies substantial uncertainty about the true expected premiums.

One implication of the expected return equation of the three-factor model is that the intercept α_i in the time-series regression,

$$R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \beta_{is}SMB_t + \beta_{ih}HML_t + \varepsilon_{it},$$

is zero for all assets i. Using this criterion, Fama and French (1993, 1996) find that the model captures much of the variation in average return for portfolios formed on size, book-to-market equity and other price ratios that cause problems for the CAPM. Fama and French (1998) show that an international version of the model performs better than an international CAPM in describing average returns on portfolios formed on scaled price variables for stocks in 13 major markets.

The three-factor model is now widely used in empirical research that requires a model of expected returns. Estimates of α_i from the time-series regression above are used to calibrate how rapidly stock prices respond to new information (for example, Loughran and Ritter, 1995; Mitchell and Stafford, 2000). They are also used to measure the special information of portfolio managers, for example, in Carhart's (1997) study of mutual fund performance. Among practitioners like Ibbotson Associates, the model is offered as an alternative to the CAPM for estimating the cost of equity capital.

From a theoretical perspective, the main shortcoming of the three-factor model is its empirical motivation. The small-minus-big (SMB) and high-minus-low (HML) explanatory returns are not motivated by predictions about state variables of concern to investors. Instead they are brute force constructs meant to capture the patterns uncovered by previous work on how average stock returns vary with size and the book-to-market equity ratio.

But this concern is not fatal. The ICAPM does not require that the additional portfolios used along with the market portfolio to explain expected returns "mimic" the relevant state variables. In both the ICAPM and the arbitrage pricing theory, it suffices that the additional portfolios are well diversified (in the terminology of Fama, 1996, they are multifactor minimum variance) and that they are sufficiently different from the market portfolio to capture covariation in returns and variation in expected returns missed by the market portfolio. Thus, adding diversified portfolios that capture covariation in returns and variation in average returns left unexplained by the market is in the spirit of both the ICAPM and the Ross's arbitrage pricing theory.

The behavioralists are not impressed by the evidence for a risk-based explanation of the failures of the CAPM. They typically concede that the three-factor model captures covariation in returns missed by the market return and that it picks up much of the size and value effects in average returns left unexplained by the CAPM. But their view is that the average return premium associated with the model's book-to-market factor—which does the heavy lifting in the improvements to the CAPM—is itself the result of investor overreaction that happens to be correlated across firms in a way that just looks like a risk story. In short, in the behavioral view, the market tries to set CAPM prices, and violations of the CAPM are due to mispricing.

The conflict between the behavioral irrational pricing story and the rational risk story for the empirical failures of the CAPM leaves us at a timeworn impasse. Fama (1970) emphasizes that the hypothesis that prices properly reflect available information must be tested in the context of a model of expected returns, like the CAPM. Intuitively, to test whether prices are rational, one must take a stand on what the market is trying to do in setting prices—that is, what is risk and what is the relation between expected return and risk? When tests reject the CAPM, one cannot say whether the problem is its assumption that prices are rational (the behavioral view) or violations of other assumptions that are also necessary to produce the CAPM (our position).

Fortunately, for some applications, the way one uses the three-factor model does not depend on one's view about whether its average return premiums are the rational result of underlying state variable risks, the result of irrational investor behavior or sample specific results of chance. For example, when measuring the response of stock prices to new information or when evaluating the performance of managed portfolios, one wants to account for known patterns in returns and average returns for the period examined, whatever their source. Similarly, when estimating the cost of equity capital, one might be unconcerned with whether expected return premiums are rational or irrational since they are in either case part of the opportunity cost of equity capital (Stein, 1996). But the cost of capital is forward looking, so if the premiums are sample specific they are irrelevant.

The three-factor model is hardly a panacea. Its most serious problem is the momentum effect of Jegadeesh and Titman (1993). Stocks that do well relative to the market over the last three to twelve months tend to continue to do well for the next few months, and stocks that do poorly continue to do poorly. This momentum effect is distinct from the value effect captured by book-to-market equity and other price ratios. Moreover, the momentum effect is left unexplained by the three-factor model, as well as by the CAPM. Following Carhart (1997), one response is to add a momentum factor (the difference between the returns on diversified portfolios of short-term winners and losers) to the three-factor model. This step is again legitimate in applications where the goal is to abstract from known patterns in average returns to uncover information-specific or manager-specific effects. But since the momentum effect is short-lived, it is largely irrelevant for estimates of the cost of equity capital.

Another strand of research points to problems in both the three-factor model and the CAPM. Frankel and Lee (1998), Dechow, Hutton and Sloan (1999), Piotroski (2000) and others show that in portfolios formed on price ratios like book-to-market equity, stocks with higher expected cash flows have higher average returns that are not captured by the three-factor model or the CAPM. The authors interpret their results as evidence that stock prices are irrational, in the sense that they do not reflect available information about expected profitability.

In truth, however, one can't tell whether the problem is bad pricing or a bad asset pricing model. A stock's price can always be expressed as the present value of expected future cash flows discounted at the expected return on the stock (Campbell and Shiller, 1989; Vuolteenaho, 2002). It follows that if two stocks have the same price, the one with higher expected cash flows must have a higher expected return. This holds true whether pricing is rational or irrational. Thus, when one observes a positive relation between expected cash flows and expected returns that is left unexplained by the CAPM or the three-factor model, one can't tell whether it is the result of irrational pricing or a misspecified asset pricing model.

The Market Proxy Problem

Roll (1977) argues that the CAPM has never been tested and probably never will be. The problem is that the market portfolio at the heart of the model is theoretically and empirically elusive. It is not theoretically clear which assets (for example, human capital) can legitimately be excluded from the market portfolio, and data availability substantially limits the assets that are included. As a result, tests of the CAPM are forced to use proxies for the market portfolio, in effect testing whether the proxies are on the minimum variance frontier. Roll argues that because the tests use proxies, not the true market portfolio, we learn nothing about the CAPM.

We are more pragmatic. The relation between expected return and market beta of the CAPM is just the minimum variance condition that holds in any efficient portfolio, applied to the market portfolio. Thus, if we can find a market proxy that is on the minimum variance frontier, it can be used to describe differences in expected returns, and we would be happy to use it for this purpose. The strong rejections of the CAPM described above, however, say that researchers have not uncovered a reasonable market proxy that is close to the minimum variance frontier. If researchers are constrained to reasonable proxies, we doubt they ever will.

Our pessimism is fueled by several empirical results. Stambaugh (1982) tests the CAPM using a range of market portfolios that include, in addition to U.S. common stocks, corporate and government bonds, preferred stocks, real estate and other consumer durables. He finds that tests of the CAPM are not sensitive to expanding the market proxy beyond common stocks, basically because the volatility of expanded market returns is dominated by the volatility of stock returns.

One need not be convinced by Stambaugh's (1982) results since his market proxies are limited to U.S. assets. If international capital markets are open and asset prices conform to an international version of the CAPM, the market portfolio should include international assets. Fama and French (1998) find, however, that betas for a global stock market portfolio cannot explain the high average returns observed around the world on stocks with high book-to-market or high earnings-price ratios.

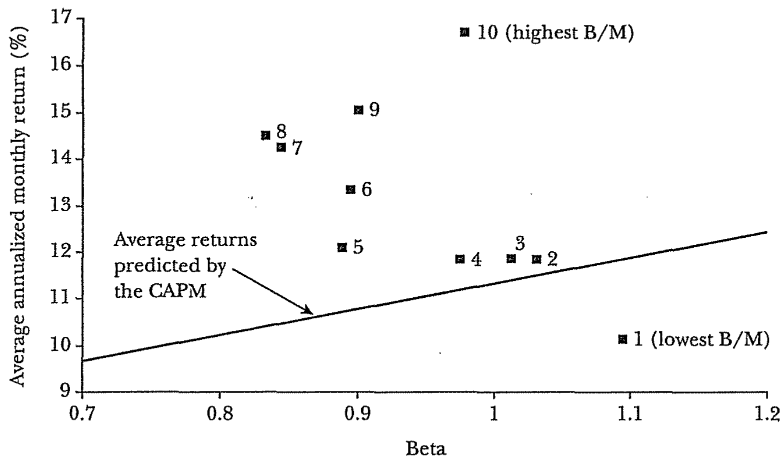
A major problem for the CAPM is that portfolios formed by sorting stocks on price ratios produce a wide range of average returns, but the average returns are not positively related to market betas (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1996, 1998). The problem is illustrated in Figure 3, which shows average returns and betas (calculated with respect to the CRSP value-weight portfolio of NYSE, AMEX and NASDAQ stocks) for July 1963 to December 2003 for ten portfolios of U.S. stocks formed annually on sorted values of the book-to-market equity ratio (B/M).[6]

Average returns on the B/M portfolios increase almost monotonically, from 10.1 percent per year for the lowest B/M group (portfolio 1) to an impressive 16.7 percent for the highest (portfolio 10). But the positive relation between beta and average return predicted by the CAPM is notably absent. For example, the portfolio with the lowest book-to-market ratio has the highest beta but the lowest average return. The estimated beta for the portfolio with the highest book-to-market ratio and the highest average return is only 0.98. With an average annualized value of the riskfree interest rate, R_f, of 5.8 percent and an average annualized market premium, $R_M - R_f$, of 11.3 percent, the Sharpe-Lintner CAPM predicts an average return of 11.8 percent for the lowest B/M portfolio and 11.2 percent for the highest, far from the observed values, 10.1 and 16.7 percent. For the Sharpe-Lintner model to "work" on these portfolios, their market betas must change dramatically, from 1.09 to 0.78 for the lowest B/M portfolio and from 0.98 to 1.98 for the highest. We judge it unlikely that alternative proxies for the market portfolio will produce betas and a market premium that can explain the average returns on these portfolios.

It is always possible that researchers will redeem the CAPM by finding a reasonable proxy for the market portfolio that is on the minimum variance frontier. We emphasize, however, that this possibility cannot be used to justify the way the CAPM is currently applied. The problem is that applications typically use the same

[6] Stock return data are from CRSP, and book equity data are from Compustat and the Moody's Industrials, Transportation, Utilities and Financials manuals. Stocks are allocated to ten portfolios at the end of June of each year t (1963 to 2003) using the ratio of book equity for the fiscal year ending in calendar year $t - 1$, divided by market equity at the end of December of $t - 1$. Book equity is the book value of stockholders' equity, plus balance sheet deferred taxes and investment tax credit (if available), minus the book value of preferred stock. Depending on availability, we use the redemption, liquidation or par value (in that order) to estimate the book value of preferred stock. Stockholders' equity is the value reported by Moody's or Compustat, if it is available. If not, we measure stockholders' equity as the book value of common equity plus the par value of preferred stock or the book value of assets minus total liabilities (in that order). The portfolios for year t include NYSE (1963–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stocks with positive book equity in $t - 1$ and market equity (from CRSP) for December of $t - 1$ and June of t. The portfolios exclude securities CRSP does not classify as ordinary common equity. The breakpoints for year t use only securities that are on the NYSE in June of year t.

Figure 3
Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on B/M, 1963–2003



market proxies, like the value-weight portfolio of U.S. stocks, that lead to rejections of the model in empirical tests. The contradictions of the CAPM observed when such proxies are used in tests of the model show up as bad estimates of expected returns in applications; for example, estimates of the cost of equity capital that are too low (relative to historical average returns) for small stocks and for stocks with high book-to-market equity ratios. In short, if a market proxy does not work in tests of the CAPM, it does not work in applications.

Conclusions

The version of the CAPM developed by Sharpe (1964) and Lintner (1965) has never been an empirical success. In the early empirical work, the Black (1972) version of the model, which can accommodate a flatter tradeoff of average return for market beta, has some success. But in the late 1970s, research begins to uncover variables like size, various price ratios and momentum that add to the explanation of average returns provided by beta. The problems are serious enough to invalidate most applications of the CAPM.

For example, finance textbooks often recommend using the Sharpe-Lintner CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. The typical market portfolio in these exercises includes just U.S. common stocks. But empirical work, old and new, tells us that the relation between beta and average return is flatter than predicted by the Sharpe-Lintner version of the CAPM. 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.[7]

The CAPM is also often used to measure the performance of mutual funds and other managed portfolios. The approach, dating to Jensen (1968), is to estimate the CAPM time-series regression for a portfolio and use the intercept (Jensen's alpha) to measure abnormal performance. The problem is that, because of the empirical failings of the CAPM, even passively managed stock portfolios produce abnormal returns if their investment strategies involve tilts toward CAPM problems (Elton, Gruber, Das and Hlavka, 1993). For example, funds that concentrate on low beta stocks, small stocks or value stocks will tend to produce positive abnormal returns relative to the predictions of the Sharpe-Lintner CAPM, even when the fund managers have no special talent for picking winners.

The CAPM, like Markowitz's (1952, 1959) portfolio model on which it is built, is nevertheless a theoretical tour de force. We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's (1973) ICAPM. But we also warn students that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications.

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[7] The problems are compounded by the large standard errors of estimates of the market premium and of betas for individual stocks, which probably suffice to make CAPM estimates of the cost of equity rather meaningless, even if the CAPM holds (Fama and French, 1997; Pastor and Stambaugh, 1999). For example, using the U.S. Treasury bill rate as the risk-free interest rate and the CRSP value-weight portfolio of publicly traded U.S. common stocks, the average value of the equity premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, with a standard error of 2.4 percent. The two standard error range thus runs from 3.5 percent to 13.1 percent, which is sufficient to make most projects appear either profitable or unprofitable. This problem is, however, hardly special to the CAPM. For example, expected returns in all versions of Merton's (1973) ICAPM include a market beta and the expected market premium. Also, as noted earlier the expected values of the size and book-to-market premiums in the Fama-French three-factor model are also estimated with substantial error.

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Size as a Predictor of Equity Returns

The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns – as size *decreases*, returns tend to *increase*, and vice versa.[1]

Traditionally, researchers have used market value of equity (market capitalization, or simply "market cap") as a measure of size in conducting historical rate of return studies. However, as we discuss later in this chapter, market cap is not the only measure of size that can be used to predict return, nor is it necessarily the best measure of size to use.

Much of the research of the size effect relies on the data provided by the Center for Research in Security Prices (CRSP) databases at the University of Chicago. The CRSP database includes U.S. equity total returns (capital appreciation plus dividends) going back to 1926.

The CRSP databases enabled researchers to look at stocks with different characteristics and analyze how their returns differed. One of the first characteristics that researchers analyzed was large-market-capitalization (large-cap) companies versus small-market-capitalization (small-cap) companies.

For example, a 1981 study by Rolf Banz examined the returns of New York Stock Exchange (NYSE) small-cap companies compared to the returns of NYSE large-cap companies over the period 1926–1975.[2] What Banz found was that the returns of small-cap companies were *greater* than the returns for large-cap companies. Banz's 1981 study is often cited as the first comprehensive study of the size effect.

Possible Explanations for the Greater Returns of Smaller Companies

Some valuation analysts treat small firms as equivalent to scaled-down large firms. This is likely an erroneous assumption.

There are theoretical reasons for the greater returns of smaller companies (i.e., the "size effect"), which might include: (i) small stocks are less liquid (with higher associated

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2 Rolf W. Banz, "The Relationship between Return and Market Value of Common Stocks", *Journal of Financial Economics* (March 1981): 3–18. This paper is often cited as the first comprehensive study of the size effect.

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9

Capital Budgeting and Risk

Long before the development of modern theories linking risk and expected return, smart financial managers adjusted for risk in capital budgeting. They realized intuitively that, other things being equal, risky projects are less desirable than safe ones. Therefore financial managers demanded a higher rate of return from risky projects, or they based their decisions on conservative estimates of the cash flows.

Various rules of thumb are often used to make these risk adjustments. For example, many companies estimate the rate of return required by investors in their securities and use the **company cost of capital** to discount the cash flows on all new projects. Since investors require a higher rate of return from a very risky company, such a firm will have a higher company cost of capital and will set a higher discount rate for its new investment opportunities. For example, in Table 8-1 we estimated that investors expected a rate of return of .163 or about 16.5 percent from Microsoft common stock. Therefore, according to the company cost of capital rule, Microsoft should have been using a 16.5 percent discount rate to compute project net present values.[1]

This is a step in the right direction. Even though we can't measure risk or the expected return on risky securities with absolute precision, it is still reasonable to assert that Microsoft faced more risk than the average firm and, therefore, should have demanded a higher rate of return from its capital investments.

But the company cost of capital rule can also get a firm into trouble if the new projects are more or less risky than its existing business. Each project should be evaluated at its *own* opportunity cost of capital. This is a clear implication of the value-additivity principle introduced in Chapter 7. For a firm composed of assets A and B, the firm value is

$$\text{Firm value} = \text{PV(AB)} = \text{PV(A)} + \text{PV(B)} = \text{sum of separate asset values}$$

Here PV(A) and PV(B) are valued just as if they were mini-firms in which stockholders could invest directly. Investors would value A by discounting its forecasted cash flows at a rate reflecting the risk of A. They would value B by discounting at a rate reflecting the risk of B. The two discount rates will, in general, be different.

[1]Microsoft did not use any significant amount of debt financing. Thus its cost of capital is the rate of return investors expect on its common stock. The complications caused by debt are discussed later in this chapter.

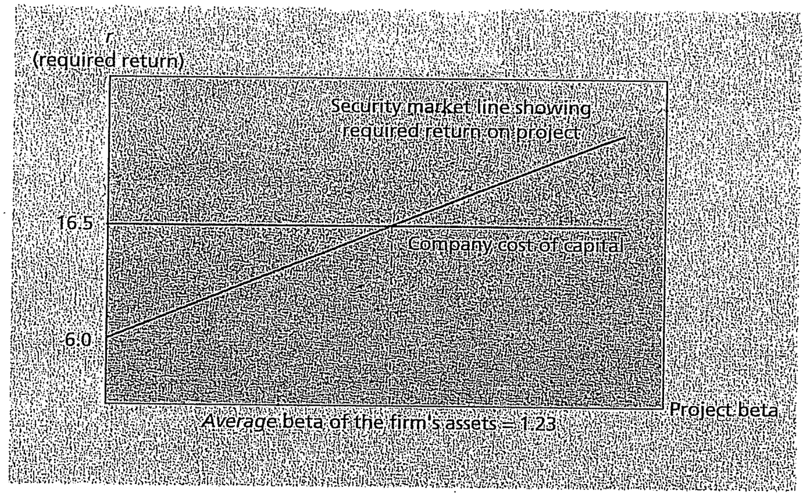

Figure 9-1 A comparison between the company cost of capital rule and the required return under the capital asset pricing model. Microsoft's company cost of capital is about 16.5 percent. This is the correct discount rate only if the project beta is 1.23. In general, the correct discount rate increases as project beta increases. Microsoft should accept projects with rates of return above the security market line relating required return to beta.

If the firm considers investing in a third project C, it should also value C as if C were a mini-firm. That is, the firm should discount the cash flows of C at the expected rate of return that investors would demand to make a separate investment in C. *The true cost of capital depends on the use to which the capital is put.*

This means that Microsoft should accept any project that more than compensates for the *project's beta*. In other words, Microsoft should accept any project lying above the upward-sloping line that links expected return to risk in Figure 9-1. If the project has a high risk, Microsoft needs a higher prospective return than if the project has a low risk. Now contrast this with the company cost of capital rule, which is to accept any project *regardless of its risk* as long as it offers a higher return than the *company's* cost of capital. In terms of Figure 9-1, the rule tells Microsoft to accept any project above the horizontal cost-of-capital line, i.e., any project offering a return of more than 16.5 percent.

It is clearly silly to suggest that Microsoft should demand the same rate of return from a very safe project as from a very risky one. If Microsoft used the company cost of capital rule, it would reject many good low-risk projects and accept many poor high-risk projects. It is also silly to suggest that just because Duke Power has a low company cost of capital, it is justified in accepting projects that Microsoft would reject. If you followed such a rule to its seemingly logical conclusion, you would think it possible to enlarge the company's investment opportunities by investing a large sum in Treasury bills. That would make the common stock safe and create a low company cost of capital.[2]

The notion that each company has some individual discount rate or cost of capital is widespread, but far from universal. Many firms require different returns from different categories of investment. For example, discount rates might be set as follows:

[2]If the present value of an asset depended on the identity of the company that bought it, present values would not add up. Remember, a good project is a good project is a good project.

Category	Discount Rate
Speculative ventures	30%
New products	20%
Expansion of existing business	15% (company cost of capital)
Cost improvement, known technology	10%

The capital asset pricing model is widely used by large corporations to estimate the discount rate. It states

$$\text{Expected project return} = r = r_f + (\text{project beta})(r_m - r_f)$$

To calculate this, you have to figure out the project beta. Before thinking about the betas of individual projects, we will look at some problems you would encounter in using beta to estimate a company's cost of capital. It turns out that beta is difficult to measure accurately for an individual firm: Much greater accuracy can be achieved by looking at an average of similar companies. But then we have to define *similar*. Among other things, we will find that a firm's borrowing policy affects its stock beta. It would be misleading, e.g., to average the betas of Chrysler, which has been a heavy borrower, and General Motors, which has generally borrowed less.

The company cost of capital is the correct discount rate for projects that have the same risk as the company's existing business but *not* for those projects that are safer or riskier than the company's average. The problem is to judge the relative risks of the projects available to the firm. To handle that problem, we will need to dig a little deeper and look at what features make some investments riskier than others. After you know *why* AT&T stock has less market risk than, say, Ford Motor, you will be in a better position to judge the relative risks of capital investment opportunities.

There is still another complication: Project betas can shift over time. Some projects are safer in youth than in old age; others are riskier. In this case, what do we mean by *the* project beta? There may be a separate beta for each year of the project's life. To put it another way, can we jump from the capital asset pricing model, which looks out one period into the future, to the discounted-cash-flow formula that we developed in Chapters 2 and 6 for valuing long-lived assets? Most of the time it is safe to do so, but you should be able to recognize and deal with the exceptions.

We will use the capital asset pricing model, or CAPM, throughout this chapter. But don't infer that the CAPM is the last word on risk and return. The principles and procedures covered in this chapter work just as well with other models such as arbitrage pricing theory (APT). For example, we could have started with an APT estimate of the expected rate of return on Microsoft stock; the discussion of company and project costs of capital would have followed exactly.

9.1 MEASURING BETAS

Suppose that you were considering an across-the-board expansion by your firm. Such an investment would have about the same degree of risk as the existing business. Therefore you should discount the projected flows at the company cost of capital. To estimate that, you could begin by estimating the beta of the company's stock.

An obvious way to measure the beta of the stock is to look at how its price has responded in the past to market movements. For example, in Figure 9-2*a* and *b* we have plotted monthly rates of return from AT&T and Hewlett-Packard against mar-

Thus we could view the project as offering an expected payoff of $.5(1500) + .5(0) = 750$, or \$750,000, at $t = 1$ on a \$125,000 investment at $t = 0$. Of course, the certainty equivalent of the payoff is less than \$750,000, but the difference would have to be very large to justify rejecting the project. For example, if the certainty equivalent is half the forecasted cash flow and the risk-free rate is 7 percent, the project is worth \$225,500:

$$\text{NPV} = C_0 + \frac{\text{CEQ}_1}{1 + r_f}$$

$$= -125 + \frac{.5(750)}{1.07} = 225.5, \text{ or } \$225{,}500$$

This is not bad for a \$125,000 investment—and quite a change from the negative NPV that management got by discounting all future cash flows at 25 percent.

A Common Mistake

You sometimes hear people say that because distant cash flows are "riskier," they should be discounted at a higher rate than earlier cash flows. That is quite wrong: Using the same risk-adjusted discount rate for each year's cash flow implies a larger deduction for risk from the later cash flows. The reason is that the discount rate compensates for the risk borne *per period*. The more distant the cash flows, the greater the number of periods and the larger the *total* risk adjustment.

It makes sense to use a single risk-adjusted discount rate as long as the project has the same market risk at each point in its life. But look out for exceptions like the electric mop project, where market risk changes as time passes.

9-6 SUMMARY

In Chapter 8 we set out some basic principles for valuing risky assets. In this chapter we have shown you how to apply these principles to practical situations.

The problem is easiest when you believe that the project has the same market risk as the company's existing assets. In this case, the required return equals the required return on a portfolio of the company's securities. This is called the *company cost of capital*.

Capital asset pricing theory states that the required return on any asset depends on its risk. In this chapter we have defined risk as beta and used the capital asset pricing model to calculate expected returns.

The most common way to estimate the beta of a stock is to figure out how the stock price has responded to market changes in the past. Of course, this will give you only an estimate of the stock's true beta. You may get a more reliable figure if you calculate an industry beta for a group of similar companies.

Suppose that you now have an estimate of the stock's beta. Can you plug that into the capital asset pricing model to find the company's cost of capital? No, the stock beta may reflect both business and financial risk. Whenever a company borrows money, it increases the beta (and the expected return) of its stock. Remember, the company cost of capital is the expected return on a portfolio of all the firm's securities, not just the common stock. You can calculate it by estimating the expected return on each of the securities and then taking a weighted average of these separate returns. Or you can calculate the beta of the portfolio of securities and then plug this *asset beta* into the capital asset pricing model.

The company cost of capital is the correct discount rate for projects that have the same risk as the company's existing business. Many firms, however, use the company cost of capital to discount the forecasted cash flows on all new projects. This is a dangerous procedure. In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is *project risk* that counts. Of course the company cost of capital is fine as a discount rate for average-risk projects. It is also a useful starting point for estimating discount rates for safer or riskier projects.

We cannot give you a neat formula that will allow you to estimate project betas, but we can give you some clues. First, avoid adding fudge factors to discount rates to offset worries about bad project outcomes. Adjust cash-flow forecasts to give due weight to bad outcomes as well as good; *then* ask whether the chance of bad outcomes adds to the project's market risk. Second, you can often identify the characteristics of a high- or low-beta project even when the project beta cannot be calculated directly. For example, you can try to figure out how much the cash flows are affected by the overall performance of the economy: Cyclical investments are generally high-beta investments. You can also look at the project's operating leverage: Fixed production charges work like fixed debt charges; i.e., they increase beta.

There is one more fence to jump. Most projects produce cash flows for several years. Firms generally use the same risk-adjusted rate r to discount each of these cash flows. When they do this, they are implicitly assuming that cumulative risk increases at a constant rate as you look further into the future. That assumption is usually reasonable. It is precisely true when the project's future beta will be constant, i.e., when risk *per period* is constant.

But exceptions sometimes prove the rule. Be on the alert for projects where risk clearly does *not* increase steadily. In these cases, you should break the project into segments within which the same discount rate can be reasonably used. Or you should use the certainty-equivalent version of the DCF model, which allows separate risk adjustments to each period's cash flow.

APPENDIX: USING THE CAPITAL ASSET PRICING MODEL TO CALCULATE CERTAINTY EQUIVALENTS

When calculating present value, you can take account of risk in either of two ways. You can discount the expected cash flow C_1 by the risk-adjusted discount rate r:

$$\text{PV} = \frac{C_1}{1 + r}$$

Alternatively, you can discount the certainty-equivalent cash flow CEQ_1 by the risk-free rate of interest r_f:

$$\text{PV} = \frac{\text{CEQ}_1}{1 + r_f}$$

In this appendix we show how you can derive CEQ_1 from the capital asset pricing model.

We know from our present value formula that $1 + r$ equals the expected dollar payoff on the asset divided by its present value:

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traded, then we cannot calculate the firm's beta. For the privately owned firm, we might use the so-called "pure play" CAPM technique. This involves finding a firm in the same line of business that does have public equity, estimating its beta, and then using this beta as a proxy for that of the small business in question.

To illustrate the pure play approach, again consider BTG. The firm is not publicly traded, so we cannot estimate its beta. However, data are available on more established firms, such as Genentech and Genetic Industries, so we could use their betas as representative of the biological and genetic engineering industry. Of course, these firms' betas would have to be subjectively modified to reflect their larger sizes and more established positions, as well as to take account of the differences in the nature of their products and their capital structures as compared to those of BTG. Still, as long as there are public companies in similar lines of business available for comparison, the estimates of their betas can be used to help estimate the cost of capital of a firm whose equity is not publicly traded. Note that a "liquidity premium" as discussed in Chapter 3 would also have to be added to reflect the illiquidity of the small, nonpublic firm's stock.

Flotation Costs for Small Issues

When external equity capital is raised, flotation costs increase the cost of equity capital beyond what it would be for internal funds. These external flotation costs are especially significant for smaller firms, and they can substantially affect capital budgeting decisions involving external equity funds. To illustrate this point, consider a firm that is expected to pay constant dividends forever, and hence whose growth rate is zero. In this case, if F is the percentage flotation cost, then the cost of equity capital is $k_e = D_1/[P_0(1 - F)]$. The higher the flotation cost, the higher the cost of external equity.

How big is F? According to the latest Securities and Exchange Commission data, the average flotation cost of large common stock offerings (more than $50 million) is only about 4 percent. For a firm that is expected to provide a 15 percent dividend yield (that is, $D_1/P_0 = 15\%$), the cost of equity is $15\%/(1 - 0.04)$, or 15.6 percent. However, the SEC's data on small stock offerings (less than $1 million) show that flotation costs for such issues average about 21 percent. Thus, the cost of equity capital in the preceding example would be $15\%/(1 - 0.21)$, or about 19 percent. When we compare this to the 15.6 percent for large offerings, it is clear that a small firm would have to earn considerably more on the same project than a large firm. Small firms are therefore at a substantial disadvantage because of the effects of flotation costs.

The Small-Firm Effect

A number of researchers have observed that portfolios of small-firm stocks have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firm to provide average returns in the stock market that are higher than those of large firms. In reality, it is bad news for the small firm; what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms. Therefore, the cost of equity capital is higher for small firms. This compounds the high flotation cost problem noted above.

It may be argued that stocks of small firms are riskier than those of large ones and that this accounts for the differences in returns. It is true that academic research usually finds that betas are higher on average for small firms than for large ones. However, the larger returns for small firms remain larger even after adjusting for the effects of their higher risks as reflected in their beta coefficients.

The small-firm effect is an anomaly in the sense that it is not consistent with the CAPM theory. Still, higher returns reflect a higher cost of capital, so we must conclude that smaller firms do have higher capital costs than otherwise similar larger firms. The manager of a small firm should take this factor into account when estimating his or her firm's cost of equity capital. In general, the cost of equity capital appears to be about four percentage points higher for small firms (those with market values of less than $20 million) than for large, New York Stock Exchange firms with similar risk characteristics.

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Estimates

Exp Earnings Date	2/28/23	Earnings ESP	0.00%
Current Quarter	0.84	Current Year	2.50

EPS Last Quarter	0.69	Next Year	2.71
Last EPS Surprise	-1.43%	EPS (TTM)	2.33
ABR	3.80	P/E (F1)	35.15

Growth Estimates	AWR	IND	S&P
Current Qtr (12/2022)	52.73	1.82	-3.93
Next Qtr (03/2023)	42.11	56.87	7.37
Current Year (12/2022)	1.21	6.70	6.80
Next Year (12/2023)	8.40	18.70	-5.53
Past 5 Years	8.40	2.50	13.40
Next 5 Years	NA	10.70	NA
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	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Zacks Consensus Estimate	138.00M	113.00M	514.50M	521.00M
# of Estimates	1	1	2	2
High Estimate	138.00M	113.00M	517.00M	527.00M
Low Estimate	138.00M	113.00M	512.00M	515.00M
Year ago Sales	116.62M	108.57M	498.85M	514.50M
Year over Year Growth Est.	18.33%	4.08%	3.14%	1.26%

Earnings Estimates

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Zacks Consensus Estimate	0.84	0.54	2.50	2.71
# of Estimates	1	1	2	2
Most Recent Consensus	0.84	0.54	2.55	2.71
High Estimate	0.84	0.54	2.55	2.71
Low Estimate	0.84	0.54	2.45	2.71
Year ago EPS	0.55	0.38	2.47	2.50
Year over Year Growth Est.	52.73%	42.11%	1.21%	8.40%

Agreement - Estimate Revisions

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	1
Up Last 60 Days	0	0	0	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0
Down Last 60 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Current	0.84	0.54	2.50	2.71
7 Days Ago	0.84	0.54	2.50	2.71
30 Days Ago	0.84	0.54	2.51	2.71
60 Days Ago	0.84	0.54	2.51	2.71
90 Days Ago	0.78	0.54	2.52	2.71

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Most Accurate Estimate	0.84	0.54	2.55	2.71
Zacks Consensus Estimate	0.84	0.54	2.50	2.71
Earnings ESP	0.00%	0.00%	2.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (9/2022)	Quarter Ending (6/2022)	Quarter Ending (3/2022)	Quarter Ending (12/2021)	Average Surprise
Reported	0.69	0.71	0.38	0.55	NA
Estimate	0.70	0.77	0.54	0.50	NA
Difference	-0.01	-0.06	-0.16	0.05	-0.05
Surprise	-1.43%	-7.79%	-29.63%	10.00%	-7.21%

Quarterly Estimates By Analyst

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American Water Works (AWK)

(Real Time Quote from BATS)

$158.82 USD

-0.60 (-0.38%)

Updated Jan 13, 2023 03:22 PM ET

Add to portfolio

Zacks Rank:
3-Hold 3

Style Scores:
D Value | D Growth | C Momentum | D VGM

Industry Rank:
Top 31% (78 out of 250)

Industry: Utility - Water Supply

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American Water Works (AWK) Quote Overview » Estimates » American Water Works (AWK) Detailed Earnings Estimates

Detailed Estimates

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Estimates

Exp Earnings Date	2/15/23	Earnings ESP	0.00%
Current Quarter	0.75	Current Year	4.46

EPS Last Quarter	1.63	Next Year	4.78
Last EPS Surprise	9.40%	EPS (TTM)	4.55
ABR	2.67	P/E (F1)	33.37

Growth Estimates	AWK	IND	S&P
Current Qtr (12/2022)	-11.76	1.82	-3.93
Next Qtr (03/2023)	-6.90	56.87	7.37
Current Year (12/2022)	4.94	6.70	6.80
Next Year (12/2023)	7.17	18.70	-5.53
Past 5 Years	8.40	2.50	13.40
Next 5 Years	8.10	10.70	NA
PE	33.37	37.20	17.91
PEG Ratio	4.13	3.48	NA

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Premium Research for AWK

Zacks Rank	**Hold 3**
Zacks Industry Rank	Top 31% (78 out of 250)
Zacks Sector Rank	Top 6% (1 out of 16)
Style Scores	**D Value | D Growth | C Momentum | D VGM**
Earnings ESP	0.00%
Research Reports for AWK	Analyst | Snapshot

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Research for AWK

Price and EPS Surprise Chart

1 Month | 3 Months | YTD

Interactive Chart | Fundamental Chart

Sales Estimates

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Zacks Consensus Estimate	923.00M	915.00M	3.78B	4.12B
# of Estimates	1	1	1	1
High Estimate	923.00M	915.00M	3.78B	4.12B
Low Estimate	923.00M	915.00M	3.78B	4.12B
Year ago Sales	951.00M	842.00M	3.93B	3.78B
Year over Year Growth Est.	-2.94%	8.67%	-3.72%	8.91%

Earnings Estimates

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Zacks Consensus Estimate	0.75	0.81	4.46	4.78
# of Estimates	1	1	4	4
Most Recent Consensus	0.75	0.81	4.47	4.78
High Estimate	0.75	0.81	4.49	4.82
Low Estimate	0.75	0.81	4.44	4.73
Year ago EPS	0.85	0.87	4.25	4.46
Year over Year Growth Est.	-11.76%	-6.90%	4.94%	7.06%

Agreement - Estimate Revisions

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Current	0.75	0.81	4.46	4.78
7 Days Ago	0.75	0.81	4.46	4.78
30 Days Ago	0.75	0.81	4.46	4.78
60 Days Ago	0.75	0.81	4.46	4.78
90 Days Ago	0.85	0.91	4.45	4.85

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Most Accurate Estimate	0.75	0.81	4.46	4.78
Zacks Consensus Estimate	0.75	0.81	4.46	4.78
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (9/2022)	Quarter Ending (6/2022)	Quarter Ending (3/2022)	Quarter Ending (12/2021)	Average Surprise
Reported	1.63	1.20	0.87	0.85	NA
Estimate	1.49	1.14	0.75	0.86	NA
Difference	0.14	0.06	0.12	-0.01	0.08
Surprise	9.40%	5.26%	16.00%	-1.16%	7.38%

Quarterly Estimates By Analyst

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California Water Service Group (CWT)
(Real Time Quote from BATS)

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$62.52 **USD**
+0.24 (0.39%)
Updated Jan 13, 2023 03:26 PM ET

Zacks Rank:
4-Sell 4
Style Scores:
D Value | B Growth | D Momentum | D VGM
Industry Rank:
Top 31% (78 out of 250)
Industry: Utility - Water Supply

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California Water Service Group (CWT) Quote Overview » Estimates » California Water Service Group (CWT) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	2/23/23	Earnings ESP	0.00%
Current Quarter	0.22	Current Year	1.60
EPS Last Quarter	1.03	Next Year	1.91
Last EPS Surprise	-11.21%	EPS (TTM)	1.48
ABR	3.50	P/E (F1)	32.66

Growth Estimates	CWT	IND	S&P
Current Qtr (12/2022)	214.29	1.82	-3.93
Next Qtr (03/2023)	300.00	56.87	7.37
Current Year (12/2022)	-18.37	6.70	6.80
Next Year (12/2023)	19.38	18.70	-5.53
Past 5 Years	11.80	2.50	13.40
Next 5 Years	NA	10.70	NA
PE	32.66	37.20	17.91
PEG Ratio	NA	3.48	NA

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Premium Research for CWT

Zacks Rank	Sell 4
Zacks Industry Rank	Top 31% (78 out of 250)
Zacks Sector Rank	Top 6% (1 out of 16)
Style Scores	D Value | B Growth | D Momentum | D VGM
Earnings ESP	0.00%
Research Reports for CWT	Analyst | Snapshot

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Research for CWT

Price and EPS Surprise Chart

1 Month 3 Months YTD

Interactive Chart | Fundamental Chart

Sales Estimates

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Zacks Consensus Estimate	180.14M	180.01M	825.89M	861.24M
# of Estimates	2	2	2	2
High Estimate	180.28M	180.01M	826.00M	863.47M
Low Estimate	180.00M	180.00M	825.78M	859.00M
Year ago Sales	173.33M	172.99M	790.91M	825.89M
Year over Year Growth Est.	3.93%	4.06%	4.42%	4.28%

Earnings Estimates

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Zacks Consensus Estimate	0.22	0.08	1.60	1.91
# of Estimates	2	2	3	3
Most Recent Consensus	0.21	0.08	1.62	1.84
High Estimate	0.22	0.08	1.63	1.94
Low Estimate	0.21	0.08	1.55	1.84
Year ago EPS	0.07	0.02	1.96	1.60
Year over Year Growth Est.	214.29%	300.00%	-18.37%	19.17%

Agreement - Estimate Revisions

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	1
Down Last 60 Days	0	0	0	1

Magnitude - Consensus Estimate Trend

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Current	0.22	0.08	1.60	1.91
7 Days Ago	0.22	0.08	1.60	1.91
30 Days Ago	0.22	0.08	1.60	1.95
60 Days Ago	0.22	0.08	1.59	1.95
90 Days Ago	0.27	0.08	1.78	2.04

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (12/2022)	Next Qtr (3/2023)	Current Year (12/2022)	Next Year (12/2023)
Most Accurate Estimate	0.22	0.08	1.60	1.84
Zacks Consensus Estimate	0.22	0.08	1.60	1.91
Earnings ESP	0.00%	0.00%	0.00%	-3.50%

Surprise - Reported Earnings History

	Quarter Ending (9/2022)	Quarter Ending (6/2022)	Quarter Ending (3/2022)	Quarter Ending (12/2021)	Average Surprise
Reported	1.03	0.36	0.02	0.07	NA
Estimate	1.16	0.60	0.05	0.20	NA
Difference	-0.13	-0.24	-0.03	-0.13	-0.13
Surprise	-11.21%	-40.00%	-60.00%	-65.00%	-44.05%

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Essential Utilities (WTRG)
(Real Time Quote from BATS)

$48.71 USD

-0.28 (-0.57%)

Updated Jan 13, 2023 03:38 PM ET

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Zacks Rank:
4-Sell 4

Style Scores:
D Value | C Growth | B Momentum | D VGM

Industry Rank:
Top 31% (78 out of 250)

Industry: Utility - Water Supply

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Essential Utilities (WTRG) Quote Overview » Estimates » Essential Utilities (WTRG) Detailed Earnings Estimates

Estimates

Exp Earnings Date	2/22/23	Earnings ESP	0.00%
Current Quarter	0.45	Current Year	1.78
EPS Last Quarter	0.26	Next Year	1.89
Last EPS Surprise	13.04%	EPS (TTM)	1.77
ABR	1.89	P/E (F1)	25.89

Growth Estimates	WTRG	IND	S&P
Current Qtr (12/2022)	2.27	1.82	-3.93
Next Qtr (03/2023)	2.63	56.87	7.37
Current Year (12/2022)	6.59	6.70	6.80
Next Year (12/2023)	6.18	18.70	-5.53
Past 5 Years	4.90	2.50	13.40
Next 5 Years	6.10	10.70	NA
PE	25.89	37.20	17.91
PEG Ratio	4.22	3.48	NA

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See Brokerage Recommendations

Premium Research for WTRG

Zacks Rank	Sell 4
Zacks Industry Rank	Top 31% (78 out of 250)
Zacks Sector Rank	Top 6% (1 out of 16)
Style Scores	D Value | C Growth | B Momentum | D VGM
Earnings ESP	0.00%
Research Reports for WTRG	Analyst | Snapshot

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Research for WTRG