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January 25, 2021

TO: Will Rosquist

FROM: Suzanne Snow

RE: Docket No. 2020.07.082 – ABACO Energy Services, LLC

Attached please find the direct testimony of Paul R. Schulz and David J. Garrett on behalf of the Montana Consumer Counsel in the above matter. Thank you.

c.c. Service List

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application of ABACO Energy Services, LLC, to Establish Service Rates and Terms of Service	))))	REGULATORY DIVISION DOCKET NO. 2020.07.082

DIRECT TESTIMONY OF

PAUL R. SCHULZ

ON BEHALF OF

THE MONTANA CONSUMER COUNSEL

JANUARY 25, 2021

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Paul R. Schulz. I am employed as a Rate Analyst with the Montana Consumer Counsel (MCC). Our offices are located at 111 N. Last Chance Gulch, Suite 1B, Helena, MT 59620-1703.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated magna cum laude with a B.A. degree in Economics from Colorado State University and I hold an M.S. degree in Accounting from the University of Virginia. I am the first recipient of the Graduate Certificate in Public Utility Regulation and Economics from New Mexico State University and one of the early recipients of the Certificate of Continuing Regulatory Education, which is endorsed by the National Association of Regulatory Utility Commissioners (NARUC) and awarded by the Institute of Public Utilities at Michigan State University. Currently, I am a member of the National Association of State Utility Consumer Advocates' Gas Committee and I am a member, and the former Meeting Registrar, of the NARUC Staff Subcommittee on Accounting and Finance where I have presented as well. In addition, since Spring of 2014 I have been on faculty at the NARUC Utility Rate School, which is held twice a year. For six years, I worked in different industries in the private sector in internal auditing, accounting, and accounting analysis positions. I was employed for over a year as a Budget Analyst with the Montana Department of Labor and Industry prior to my employment at the MCC commencing in 2009. I hold a CPA license issued by the State of Montana and am a member of the American Institute of Certified Public Accountants.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the results of my review of the various testimonies and schedules submitted by ABACO Energy Services, LLC (ABACO or AES) to support its requests, based on a 2019 test year, to increase rates and charges for propane delivery service in Big Sky, Montana. The current non-commodity rates include a volumetric O&M charge of $0.3420 per gallon of propane for both Commercial (Boyne) and Residential (Non-Boyne) customers. In addition, Commercial customers pay a volumetric Distribution charge of $0.3746/gal. and Residential customers pay $.4871/gal. for the Distribution charge. Residential customers also pay a fixed monthly service charge of $4.00, there is no fixed charge for Commercial customers.

In this present application, ABACO is requesting an O&M rate of $0.5523/gal. for Commercial (Boyne) customers, for an increase of 61.5%, and a new Distribution rate of $0.6210/gal. which is a 65.8% increase. For residential (non-Boyne) customers ABACO is seeking the same increase of 61.5% to $0.5523/gal. for the O&M rate, an increase of 57.2% to $0.7656 for the Distribution rate and an 87.5% increase of the monthly service charge from $4.00 to $7.50 per month. This is a request to increase the non-commodity revenue requirement from $608,616 to $1,002,177 for an increase of $393,561 or 64.66%. This requested revenue requirement shown on Schedule 38.5.122 is designed to generate an overall return of 16.75% on its proposed rate base of $920,494. However, 16.75% is ABACO's proposed return on equity, whereas its proposed overall rate of return is 15.81% as shown on Schedule 38.5.146.

After reviewing the Company's application as well as responses to data requests from the MCC and Boyne, USA (Boyne), my analysis indicates ABACO will have an opportunity to earn a fair and reasonable return with a non-commodity revenue requirement of $459,877 as outlined in Exhibit PRS-1 and shown graphically on Exhibit PRS-1A. Suggested adjustments follow and associated supporting exhibits PRS-2 through PRS-10 are attached. My recommendation is for a fixed charge of $6.50 per month and a single volumetric non-commodity charge of $.54373 per gallon of propane used.

II. EXPENSES

Q. WOULD YOU OUTLINE THE GENERAL BASES FOR YOUR PROPOSED ADJUSTMENTS TO OPERATING AND MAINTENANCE (O&M) EXPENSES?

A. Yes. Some of the adjustments are for items that predate the test year (2019) or extend beyond the 12-month known and measurable adjustment period (2020) and therefore do not qualify to be included in rates for recovery. They do not qualify, because either the adjustments constitute retroactive ratemaking or are not actually incurred expenses but speculative expenses that may be incurred in the future. Other adjustments involve a change to a more reasonable level of expense recovery for a particular cost category, and finally, some items I have excluded because they are not appropriately included in rates for other reasons.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE 12-MONTH ADJUSTMENT PERIOD FOLLOWING THE TEST YEAR.

A. It is important when examining test year expenses to adjust for any expenses that are non-recurring or are at apparently aberrant levels. The point of using a test year is to establish a data set that is representative of "normal" utility operations and therefore leads to the establishment of a revenue requirement that is properly aligned or matched with that level of "normal" expenses. The test year also limits what may be included in the revenue requirement to actual currently incurred expenses in the test year, so ratepayers are not charged for recovery of a non-existent expense. There is recognition of the possibility that there may be events occurring subsequent to the test year that will change what a representative year looks like going forward, and so there is the allowance for known and measurable changes if those changes meet certain qualifications and are not merely speculative. The Administrative Rules of Montana (ARM) in Rule 38.5.106 state, "However, no adjustments shall be permitted unless based on changes in facilities, operations, or costs which are known with certainty and measurable with reasonable accuracy at the time of the filing. No adjustment will be entertained unless it will become effective within 12 months of the last month of the test period as used in this section."

When a utility attempts to only forecast certain changes in costs going forward without balancing adjustments to reflect cost offsets or revenue increases that also occur over time, the adjustment process is likely to impede the cost/revenue matching objective. An adjustment that is allowed that does not meet the requirements of ARM 38.5.106 also undermines utility management's incentives to pursue cost efficiencies.

Q. PLEASE OUTLINE THE ADJUSTMENTS PROPOSED BY THE COMPANY THAT DO NOT FIT WITHIN THE TEST YEAR OR THE 12 MONTH POST TEST YEAR ADJUSTMENT PERIOD.

RENTAL EXPENSE

A. ABACO started incurring rent expense in 2019. Prior to that time there was no rental expense (See first supplemental response to MCC-002c.). In the response to MCC-002a., ABACO indicated two physical addresses for office space in Bismarck it says are used exclusively for AES. The rent for those two spaces is $1,375/mo. or $16,500 annually for a total of 1200 square feet.

In addition, ABACO is seeking to add an estimated $19,800 per year of rental expense to the revenue requirement for the potential rental of space in Big Sky. It is estimated because, as of this time, no space has been leased. As Stacy Tschider, testifies on page 7 of his testimony, "We have decided we do need to lease space and hope to do so this year if we can find the right space." This clearly does not meet the "known and measurable and in effect" requirements of ARM 38.5.106. To include this adjustment would be to charge ratepayers an additional $19,800 a year, for an estimated rental expense that will not even be incurred until some uncertain date in the future. While Mr. Tschider indicates ABACO thinks it would be worthwhile to rent space in Big Sky, ABACO has been able to operate and has chosen to operate without that space and accompanying expense for over 13 years. This is a clear example of the type of speculative expense that test year ratemaking and the requirements of ARM 38.5.106 protect consumers against. Accordingly, I am excluding the $19,800 of currently non-existent rental expense from my recommended amount for O&M expenses. This adjustment is shown on Exhibit PRS-2.

RATE CASE EXPENSE

ABACO proposes to include an estimated $100,000 for recovery for rate case expense for this current case and an additional $66,738 for expenses incurred previously that were related to other matters. The December 16, 2020 supplemental response to MCC-012, indicates that all of the expenses related to this docket were incurred in 2020. Of that $66,738, $63,220 was incurred in 2017 and 2018, prior to the test year. Pulling forward expenses from time periods prior to 2019 in this case, violates test year ratemaking and is retroactive ratemaking. In addition, those expenses were largely related to a prior filing that as Mr. Trogonoski states, "…was ultimately withdrawn by the Company after the data became stale." This occurred during a time ABACO was still contesting whether it was subject to the jurisdiction of the Montana Public Service Commission (Commission or MPSC).

My recommendation is that the $100,000 of estimated rate case expense included in ABACO's application for this docket be included for recovery and amortized over four years, totaling to $25,000/ year. The associated adjustment is shown on Exhibit PRS-2. Prudent rate case expenses are recoverable from ratepayers. The amortization of rate case expense is a component of the revenue requirement that will continue to be collected each year from ratepayers until the conclusion of a new rate case. ABACO proposes a three-year amortization schedule for these expenses. Therefore, if more time than three years elapses between rate cases, there will be excess recovery of rate case expense beyond the stated amount and if less than three years elapses there will be a shortfall in recovery. The ideal amortization period is one which matches with the typical between rate case intervals of a utility. For this utility, we do not have a history of rate cases to look at to determine a time interval. This Commission has generally used amortization periods of 3-5 years for rate case expense, so absent more specific information related to this utility, I am recommending the midpoint of four years. In addition, ABACO's estimate of $100,000 for this case is particularly high compared to that of similarly sized small water companies in terms of number of customers. Those cases have typically involved $30,000 to $40,000 of regulatory expense so a slightly longer amortization period provides some consumer protection by reducing the recurring annual expense.

Q. SHOULDN'T A UTILITY BE ALLOWED TO CHOOSE HOW MUCH TO SPEND TO CONDUCT ITS CASE?

A. That is largely true, but it is consumers that ultimately pay rate case expenses and those expenses are used to promote the interests of the utility and its investors. Those interests are often contrary to the interests of ratepayers. That is why it is important that the Commission allow only prudently incurred rate case expenses that are not at excessive levels. The Commission should consider balancing the necessity of incurring such expenses in conjunction with establishing the proper incentive to control those costs. A utility should be held, as is the usual practice with this Commission, to a reasonable estimate of its rate case expense and not simply true up those expenses to whatever it may spend by the end of a case, as is suggested in a conclusory statement by Mr. Trogonoski on page eight of his testimony.

REGULATORY COSTS

ABACO proposes to add $3,000 a year to its recoverable expenses for regulatory costs in "changing from a non-regulated entity to a regulated entity." (Statement G). This expense also is not a change that meets the requirements of ARM 38.5.106. ABACO states it has been regulated since December 2016, yet there are no expenses in its financial records for these types of filings or specifics on how the figure of $3,000 was derived. The information to fill out the annual report and file the returns for the MCC and MPSC taxes at the Montana Department of Revenue (DOR) should be readily available through the efforts of ABACO's CFO who is currently being paid $90,000 a year to work an average of 25 hours per week (See response to MCC-004c.). Filing an annual report and filing at DOR for MPSC/MCC taxes does not require an attorney, and even so, should become routine and take little time. I am recommending removing this proposed expense which is not known and measurable as shown on Exhibit PRS-2.

SALARIES

Q. HAVE THERE BEEN ANY CHANGES TO HOW ABACO MEMBER-EMPLOYEES ARE COMPENSATED IN RECENT YEARS?

A. Yes. As shown in the first supplemental response to MCC-004e., ABACO members in 2016, a time before ABACO considered itself regulated, were paid through distributions However, as shown in the attachment to MCC-004 e., from 2017 on they have received salaries.

Q. WHAT IS THE SIGNIFICANCE OF THAT CHANGE?

A. Apparently, up through 2016, the members were content to receive compensation via distributions. The significance is that distributions are sourced from retained earnings. Salaries are an expense that causes a dollar-for-dollar increase in the calculation of the revenue requirement, that is why it is important that compensation is for actual work performed and set at representative market levels for the tasks performed.

Q. IS IT IMPROPER FOR MEMBER-EMPLOYEES TO BE PAID A SALARY?

A. No, as long as work is being done and paid for at reasonable levels.

In its application, ABACO is requesting $393,223 annually for salaries and employee benefits. Of this amount, $7,689 is a proposed net increase for the on-site General Manager. The responses to MCC-004 c. and d. indicate that ABACO does not track the time spent by its employee or ABACO member employees on their job duties. So, they estimated and assumed, for establishing Member wage rates that each member spends 10-15 hours a week on ABACO business which averages to 12.5 hours/wk. or 650 hours per year. In addition, Su-Lin Tschider is estimated to spend another 10-15 hours per week on accounting and bookkeeping services, which would indicate Ms. Tschider averages 25 hours/wk. on ABACO business or 1,300 hours per year. The on-site General Manager appears to be a full-time employee.

The individual salaries of the ABACO employee and members are shown in the attachment to the response to MCC-004a., and are listed below:

Joey M. Gen. Mgr. $75,098 proposed $82,598, full-time, $39.71/hr.
Jeff Jonson, CEO $60,000, avg. 12.5 hrs. a week, $92.31/hr.
Stacy Tschider, President $60,000, avg. 12.5 hrs. a week, $92.31/hr.
Deb Jonson, Exec. Officer $60,000, avg. 12.5 hrs. a week, $92.31/hr.
Su-Lin (Melanie) Tschider, CFO $90,000, avg. 25 hrs. a week, $69.23/hr.

As ABACO indicated in the response to MCC-004d., no market studies were performed and there is no other type of documentation related to determination of compensation levels.

Upon initial examination, ABACO appears management top-heavy for such a small employee base, and these hourly rates for the four Members of ABACO, LLC seem potentially high, given the position descriptions attached to the response to MCC-004c. and attached to this testimony (Attachment A). For example, ABACO has both a President and CEO, which seems unusual in that there is only one on-site employee, and four Members who are also out of state executive employees in the organization. In fact, Jeffrey Jonson, the CEO and Stacy Tschider, the President, have identical job descriptions, so there are two individuals who both do such tasks as establish the "AES vision, mission, and overall direction, … Work with team to spread ideas and direction thought [sic] until every employee understands their expected role and responsibilities for contribution…." Formulating and implementing the strategic plan that guides the direction of AES."

This time spent on strategic planning and employee collaboration is for a regulated public utility that has argued through Mr. Tschider's testimony on page one, "…ABACO's business is limited to providing safe and reliable propane delivery services to ABACO's limited customers located in the Big Sky Mountain Village at the Big Sky Ski Resort." And on page two of his testimony, "ABACO's operating footprint is very limited." The need for two top executives, performing the same roles in a four Member, and one non-member employee organization is indeed questionable, given that ABACO is asking ratepayers to foot the bill. Regulators seek to encourage efficient operations of utilities. An organization with four top level executives and one other employee is an inefficient structure to provide service to ratepayers.

Ms. Jonson, the Executive Officer, does such things as prepare monthly statements for customers and send them in the mail. She also monitors accounts to identify overdue payments. She maintains the website and monitors propane levels. She is paid $92.31/hr. for activities that seem more akin to the duties of a bookkeeper and office manager.

For Ms. Tschider, CFO, the job description says the accounts payable and receivables processes are done by this person, although as indicated above, it is Ms. Jonson that sends out monthly statements and monitors overdue payments, so it appears she is also involved with those processes. While Ms. Tschider is listed as the CFO, Head of Customer Relations, and serves as Controller, her position pays less per hour than the Executive Officer.

Q. DID YOU ANALYZE THE LEVEL OF COMPENSATION FOR THE FOUR MEMBER EMPLOYEES OF ABACO?

A. Yes, I endeavored to derive hourly rates that would reflect local market wage rates for the described job tasks in Bismarck, North Dakota where those members are located.

I started by obtaining wage information for the Bismarck metropolitan statistical area on the United States Bureau of Labor Statistics (BLS) website[1]. The most recent data available are for May of 2019. Then, I selected the occupational titles or categories with the descriptions that best matched the job duties as described in the previously discussed descriptions attached to MCC-004. As alluded to earlier, it seems like duplicative effort and unnecessary for such a small organization, to have both a President and CEO that are performing the same duties. Therefore, I used the median wage for Chief Executives for one position, which is $58.79/hr. and then the job title of General and Operations Managers for the other position. The BLS description of General and Operations Managers encompasses more of the operationally related tasks listed in those identical ABACO job descriptions, leaving higher level activities such as providing overall direction to one executive. The median wage for this type of manager in Bismarck is $39.55/hr.

For Ms. Tschider's position, I used the overall category of Business and Financial Operations Occupations. This seemed appropriate, as her job description included such items as being Controller, Head of Customer Relations and Assistance, and Head of Human Resources and Head of regulatory and Compliance/Safety, including tasks such as handling accounts receivable and payable. In the case of ABACO, there is no

[1] https://www.bls.gov/oes/current/oes_13900.htm.

significant staff to manage, rather she takes care of those responsibilities directly. Consequently, the positions making up Business and Financial Operations Occupations is a good fit with such jobs contained therein as HR Specialist, Compliance Officers, and Accountants and Auditors. The median wage for this type of occupation in Bismarck is $31.07/hr.

Ms. Jonson's position as mentioned earlier involves bookkeeping and office management type tasks. The most appropriate classification for her position seems to be the overall category of Office and Administrative Support Occupations, which is an umbrella over some more specific positions such as Bill and Account collector, Billing and Posting Clerks, and Bookkeeping, Accounting, and Auditing Clerks which encompasses many of the tasks performed by Ms. Jonson. The median wage for this type of position in Bismarck is $18.63/hr.

In using these rates, I made another adjustment to take into account inflationary pressures on wages covering the time from mid-2019 through the end of 2020. To make this adjustment, I used the most recently available information for the BLS Employment Cost Index Summary.[2] I had to make the presumption that inflation for the last quarter of 2020 was the same as for the third quarter as that is the most recent quarter for which

[2] https://www.bls.gov/news.release/eci.nr0.htm#.

information is available. These calculations are shown in detail in Exhibit PRS-8. The resulting final wage rates are \$60.51/hr. for the President position, \$40.71/hr. for the CEO position, \$31.98/hr. for the CFO position, and \$19.18/hr. for the Executive Officer position. This is an overall 43.51% decrease to annual salaries expense as shown by ABACO for 2019, so I made a corresponding proportional decrease to employer FICA and Medicare. The total annual adjustment for salaries is \$(150,175), and when paired with the decrease of \$(10,929) for associated employer payroll taxes, the total comes to \$(161,105) as shown on Exhibit PRS-9.

PSC/MCC FEES

I applied the most recent MPSC/MCC tax rates to my recommended revenue requirement to determine the amount for these taxes. The rates for these fees are updated each year on October 1, so the most recent rates were not available when Mr. Trogonoski's testimony was filed. As of October 1, these rates are 0.347% for the MPSC tax and 0.048% for the MCC tax.[3] These amounts are shown on Exhibit PRS-4.

[3] MPSC Docket Nos. 2020.09.098 and 2020.09.099.

III. UTILITY PLANT USED IN CALCULATING RATE BASE

Q. PLEASE PROVIDE SOME BACKGROUND FOR ABACO'S SUBSTANTIAL RETROACTIVE WRITE-UP OF UTILITY PLANT BY $741,430 DATED DECEMBER OF 2016.

A. ABACO essentially resurrects plant value that was properly depreciated and that experienced physical decline between the time the utility was purchased in July of 2007 until December 2016. In fact, as shown on Schedule 38.5.124, much of that utility plant was fully depreciated as of the end of 2016 or earlier.

Q. WHAT IS ABACO'S RATIONALE FOR IGNORING OVER NINE YEARS OF DEPRECIATION AND SEEKING TO RE-RECOVER THAT PLANT VALUE FROM RATEPAYERS?

A. According to the Application, it appears to be based upon conclusory statements from Su-Lin Tschider in her testimony and further conclusory statements from Mr. Trogonoski included as a footnote in Schedule 38.5.124. Ms. Tschider opines on page three of her testimony that, "the first day the assets were put into use by and for the public was the date of this Commission's order declaring ABACO was a public utility, December 22, 2016."

Q. WHAT IS ORIGINAL COST AS USED IN UTILITY RATEMAKING IN MONTANA?

A. Montana is an original cost state or jurisdiction, which is the case for most of the states and the Federal Energy Regulatory Commission (FERC). This Commission has stated that it "is given the power to investigate and ascertain the value of the property of every public utility actually used and useful for the convenience of the public; under Mont. Code Ann. §69-3-109, the Montana Public Service Commission is obligated to eliminate from rate base all utility costs in excess of original cost."[4] As stated by the Commission in addressing an acquisition premium in Docket No. D2006.6.82, "It is a long held regulatory principle of this Commission that the value of plant in rate base is determined by original cost less depreciation. Original cost of utility property is determined when the asset is first dedicated to public service. The action of selling a utility, absent any compelling reason, is not sufficient to allow an adjustment in rate base to reflect acquisition costs."[5]

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[4] *In re Montana Power Co.,* 180 Mont. 385, 590 P.2d 1140.
[5] MPSC Order No. 6754e at ¶ 144.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE ORIGINAL COST STANDARD AND THE PURPOSES BEHIND IT.

A. The original cost standard states that rate base should be measured on the original cost (i.e., accounting book value) less depreciation of an asset when first devoted to public service. This case presents a good example of one of the purposes behind the use of original cost in rate setting. Ratepayers pay for depreciation (return *of* capital) and they also pay for a return on the undepreciated value of plant used to provide service (return *on* capital). Rate base is fundamentally the remaining unrecovered investor supplied capital, prudently invested, and employed in the provision of utility service.

Prior to December 2016, for over nine years ABACO ratepayers paid for depreciation or the return of capital to the utility. To now require ratepayers to pay for a new inflated valuation of utility plant would be to require them to pay again for capital they have already returned to the utility. Carrying forward a July 2007 purchase price to effectively re-value the utility in December 2016 would cause this double recovery. The original cost standard protects consumers from paying more than once for utility assets and also avoids encouraging the reselling or *revaluing* of utilities as a means to create phantom utility investment. Otherwise, each new owner of a utility or a current owner that commissions a new appraisal or contests "when" it became regulated would be able to recover some multiple of the purchase price of the utility through depreciation expense included in rates, even if some or all of that amount had already been collected from consumers.

Q. WHAT RATIONALE DOES MS. TSCHIDER GIVE FOR SAYING THAT ABACO'S UTILITY ASSETS WERE FIRST PLACED IN PUBLIC SERVICE ON DECEMBER 22, 2016?

A. As mentioned previously, no support for the statement is given. Whether a utility is a public utility subject to regulation by the Commission is determined by definition in statute.[6] ABACO disagreed that it met that definition when a complaint was filed against it at the Commission by Shoshone Hotel Condominium Homeowners Association in 2013.[7] ABACO argued both at the Commission and in district court that it was not subject to regulation by the Commission. In that 2013 docket, the Commission determined that "ABACO is a public utility subject to the jurisdiction of the Commission."[8] ABACO filed for judicial review of that decision in January 2017. The Commission filed a Complaint for Recovery

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[6] § 69-3-101, MCA.
[7] MPSC Docket No. D2013.9.71.
[8] MPSC Docket No. D2013.9.71, Order No. 7393c, ¶ 70 (citing § 69-3-101, MCA).

of Civil Penalties for Violation of Commission Orders a year later. Then in October of 2019, ABACO and the Commission signed a settlement agreement (Attachment B) to dismiss with prejudice ABACO's petition for judicial review, and the Commission's Complaint with prejudice. ABACO is now unilaterally claiming that it became a utility subject to regulation in December 2016. However, that was simply the date the Commission issued its Final Order. ABACO, as determined by the Commission, met the definition of a regulated public utility in that Final Order. Nothing suddenly changed in the nature or character of the utility or its operations in December of 2016.[9] Because ABACO's utility assets were placed into public service in July of 2007, original cost should be determined as of that date.

Q. DOES IT ULTIMATELY MATTER FOR SETTING RATES IN THIS CASE WHETHER ABACO ASSETS WERE FIRST PLACED INTO PUBLIC SERVICE IN JULY OF 2007 OR DECEMBER OF 2016?

A. No, in this case, the value of utility plant to put in rate base is the same either way. As was mentioned above, "It is a long held regulatory principle of this Commission that the value of plant in rate base is determined by original cost *less depreciation*. Original cost of utility property is

[9] "There were no changes in use of the Abaco system on that date." Response to Data Request BSR-014b).

determined *when* the asset is first dedicated to public service."[10] Even if ABACO's assets were improperly considered first placed into public service in December of 2016, the value of those assets at that time was the net book value on the financial records of ABACO.

Q. WOULD IT BE IMPROPER TO REVERSE OVER NINE YEARS OF DEPRECIATION AS IF IT NEVER HAPPENED?

A. Yes, it would be improper from both an accounting and regulatory standpoint and be inequitable to ratepayers.

Q. HOW WOULD IT BE IMPROPER FROM AN ACCOUNTING STANDPOINT?

A. Such an adjustment would be a clear violation of the matching principle. The matching principle requires that expenses used to generate revenues be recognized in the same time period as the associated revenues. Depreciation represents the allocation of the value of an asset over the time periods benefitted by that asset. Or stated differently, "In accounting, the term depreciation refers to the allocation of cost of a tangible asset to expense to the periods in which the asset is expected to be used to obtain the economic benefit…. The cost of an asset is initially recorded as an asset

[10] MPSC Docket No. D2006.6.82, Order No. 6754e at ¶ 144.

in accounting records because the asset will be used for many periods in future. Afterward, the portion of cost is allocated to a particular period is removed from the total cost of the asset and becomes the expense of that particular period and is matched against revenue like any other expense."[11] To now ignore the depreciation that has already been recorded by ABACO would be to violate the matching principle, expense an item twice, and pretend that those utility assets did not provide economic benefit or generate revenue for ABACO in providing service from July 2007 until December 2016.[12]

Q. HOW WOULD IT BE IMPROPER FROM A REGULATORY STANDPOINT AND BE INEQUITABLE TO RATEPAYERS?

A. First, ABACO misapprehends the use of a regulatory asset. Regulatory assets are established so that an expense that would normally be recognized by a utility in a *current* period and perhaps anticipated to be incurred in subsequent periods, may be deferred to an unknown future period for consideration of inclusion in regulated rates. In order to justify such a departure from proper matching of expenses and test year ratemaking, a utility will request an accounting order from the Commission allowing for

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[11] https://www.accountingformanagement.org/depreciation-process-cost-allocation-not-valuation/.
[12] The matching principle is discussed extensively in paragraph 41 of MPSC Order 7105f, Docket No. 2010.06.060.

the deferral of certain costs. This allows a utility to defer recognizing a current expense. The important point here is that utilities request accounting orders to defer *current* expenses for consideration of recovery in a *future* rate case. They ask the Commission at the time, or in some cases ahead of time, to allow a variance from test year ratemaking for certain well-defined expenses that are material, unplanned and outside of management control. A regulatory asset is not established after-the-fact in order to justify retroactive ratemaking. ABACO, however, is asking for the simultaneous establishment of a regulated asset and recovery for expenses incurred – and in the case of utility plant, already recovered – prior to the test year.

Secondly, even if service provided by ABACO during that time period was not considered subject to regulation, the value of those assets expensed through depreciation cannot now be considered as having rejuvenated value as regulated utility plant.[13] The assets were used in providing the same service and cannot now be fictionally restored to their July 2007 financial and physical condition to allow for double expensing and double recovery[14] through regulated rates paid by the same ABACO consumer base.

[13] MPSC Order 7105f, Docket No. 2010.06.060 at ¶ 39.
[14] Double recovery is, "A practice squarely in conflict with fundamental ratemaking practices." *Id*. at ¶49.

Q. WHAT INDICATION DO YOU HAVE THAT RECOVERY OF THAT PLANT VALUE HAS ALREADY OCCURRED?

A. First, the first footnote on Schedule 38.5.124 of ABACO's Application says that the regulatory asset ABACO is establishing, "is the difference between original cost and net book value." So, that difference would be depreciation taken since the purchase of the system in 2007 and on subsequent plant additions prior to December 2016.[15] Second, as mentioned on Schedule 38.5.124, "Depreciation life is the life used for tax purposes." Normally, an accelerated tax depreciation method would not be used for regulatory purposes, however that is what ABACO has been recording and recovering. In other words, it is the depreciation that they have been recording for tax purposes. Those returns if prepared properly would have comported with the economic substance doctrine. "The economic substance doctrine is a common law judicial doctrine that disallows tax benefits of a transaction if the transaction lacks economic substance or a business purpose. The doctrine was codified in 2010 in Sec. 7701(o)…."[16] ABACO's claimed depreciation represented the economic substance of what was happening. Second, in response to Data

[15] *See also* the response to BSR-016b), "The plant value that was depreciated through 2016 is added back to the net plant value to arrive at the original cost of the plant."
[16] https://www.journalofaccountancy.com/news/2014/oct/201411106.html.

Request BSR-006b), ABACO states that the original contract rates, "were intended to provide Abaco with a *return of* and return on its investment." That *return of* is achieved through recovery of depreciation expense.

Q. DOES ABACO QUALIFY THAT RESPONSE TO BSR-006b)?

A. Yes, further in that response ABACO states that "the parties understood that the rates would likely increase in the event the system was ever deemed a regulated public utility; and therefore the Contract also permits the rates to be increased if the operations ever became regulated by the Commission." However, I do not see where any such understanding would lead to an acceptance of double recovery of investment by the owners in utility assets.

Q. DOES THE CONTRACT BETWEEN ABACO AND BOYNE ACTUALLY INDICATE THAT IF ABACO IS SUBJECT TO COMMISSION JURISDICTION THE PARTIES UNDERSTAND THAT RATES WOULD LIKELY INCREASE?

A. No, it does not. Paragraph 7e. of the contract states, "Customer understands rates may be subject to regulation by the MPSC. If regulation occurs, Customer understands the propane rate will be based on Company's cost of service to serve Customer and other potential customers."

That paragraph indicates that it was understood that rates may be based on the cost of service. Cost of service ratemaking is grounded in well-established regulatory principles. There is no implied presumption that rates would necessarily go up when determined based on cost of service ratemaking. Cost of service ratemaking is in part designed to prevent abuses of captive consumers by a monopoly service provider, such as through the double recovery of investment, so any such presumption would seem more logically inclined to the likelihood, though not certainty, of a rate decrease.

Q. DOES ABACO INDICATE ANY REASON THAT JUSTIFIES THE USE OF A 2007 VALUE APPLIED IN 2016 BECAUSE THAT IS THE DATE OF THE ISSUANCE OF A COMMISSION ORDER?

A. Yes, in response to BSR-016a. ABACO analogizes its self-determination that it "became" a regulated public utility at the time of the Commission decision rejecting ABACO's arguments that it was not a regulated public utility, to the rate basing by NorthWestern Energy (NWE) of an acquisition premium for an interest in Colstrip Unit 4 (CU4) and for the Hydroelectric assets (Hydros) determined in two separate preapproval dockets.

ABACO claims it was a "merchant plant" prior to December 2016, like CU4 and the Hydros, and therefore it should be allowed to write-up its assets through the erasure of over nine years of depreciation as NWE was allowed to include acquisition premiums in rate base.

Q. IS ABACO'S SITUATION ANALOGOUS TO THOSE TWO SITUATIONS OF NORTHWESTERN ENERGY?

A. No, it is not. NWE was a regulated public utility purchasing merchant generating plants at prices that contained an acquisition premium (price over net book value). ABACO is a regulated public utility that argued it was not regulated and wants to undo nine years of depreciation expense and the recovery of that expense because of the time it took to resolve its contention that it was not subject to regulation. The Commission explicitly indicated that the assets NWE acquired in the CU4 and Hydros dockets were in fact merchant or unregulated properties prior to those respective acquisitions. In paragraph 235 of *Final Order 6925f* in the CU4 docket it stated, "CU4 has been a merchant plant since it began commercial operation." Paragraph 162 of *Final Order 7323k* in the Hydros docket stated, "This acquisition was made pursuant to a market purchase from a non-regulated utility, PPLM." The Commission has found that ABACO meets the definition of a regulated public utility. Nothing changed for ABACO in December 2016. The Commission has not, and should not make a contrary finding that prior to that time ABACO was a merchant plant..

Q. IS THERE ANY OTHER DIFFERENCE BETWEEN ABACO'S SITUATION AND THOSE OF NORTHWESTERN ENERGY?

A. Yes, there is a critical distinction, showing that ABACO's revaluation of its utility plant in December 2016 is faulty, even if one accepts that ABACO was previously un-regulated.

Q. WHAT IS THAT DISTINCTION?

A. For CU4, NWE had an offer to purchase (by Bicent) CU4, which the Commission used to establish a value for rate basing CU4. In the case of the Hydros, NWE had an agreement to purchase them from PPL Montana. In other words, there was an agreement, an offer, used to establish value at the time for those assets. The issue in those cases was whether NWE should be allowed (in the public interest) to rate base an acquisition premium and if so, how large should the allowable premium be. For an acquisition premium to be allowed in rate base the Commission has found that it must pass a five-part test.[17]

[17] A purchase must 1)necessary, 2) used and useful, 3)negotiated in god faith, 4) reasonable, and 5) the least cost alternative. MPSC Docket No. 86.5.28, Order 5219b, ¶ 60.

In the case of ABACO, there is no third party offer to purchase the utility from 2016 that is being used to suggest a value. There is no acquisition premium because there was no proposed acquisition. Even if the arbitrary write-up of rate base is analogized to an acquisition premium it does not meet the elements of the five-part test for inclusion in rate base. In addition, such an approach creates illogical results.

Q. EXPLAIN WHY ABACO'S APPROACH TO VALUATION CREATES ILLOGICAL RESULTS.

A. ABACO argues that it should be able to use the purchase price of the system from July 2007 as the value of the system in 2016, when the Commission determined it was subject to regulation as a public utility. Given that construct, the plant value of the utility would be the same (July 2007 number) at any point in time that the Commission may have made a decision regarding ABACO's argument that it was not regulated. The value would theoretically be the same in December of 2014 or November of 2019 or March of 2023, just depending on when the Commission rendered its decision. So, for each additional month that the Commission waited to issue its decision, it would be that much more depreciation that ABACO ratepayers would be required to eventually pay for twice.

In the case of an acquisition premium, the purchase price offered is dependent on various factors in effect at the time of an offer. With ABACO's approach, the amount of recorded and recovered depreciation and the actual physical wear on the system would all be irrelevant. This is because the purchase price in 2007 and the timing of the final adjudication of ABACO's claim that it was unregulated would be inextricably linked with no other factors being considered for determining value for rate base. As mentioned above, the Commission has said, "It is a long held regulatory principle of this Commission that the value of plant in rate base is determined by original cost less depreciation."[18] ABACO chooses to ignore the *less depreciation* aspect of using original cost to determine an amount to place in rate base.

Q. WHAT IS YOUR RECOMMENDATION FOR PLANT VALUE TO USE IN DETERMINING RATE BASE?

A. My recommendation is to use the original cost less depreciation value of plant as of the end of 2018 averaged with the end of 2019 amount with no write-up for already recovered depreciated cost and less customer contributed capital and intangible assets, for a total of $761,202.

[18] Docket No. D2006.6.82, Order No. 6754e at ¶144.

Q. DOES ABACO'S PROPOSED REGULATORY ASSET AND YOUR RECOMMENDATION REGARDING REMOVAL OF THAT "REGULATORY ASSET" AFFECT OTHER AREAS OF ABACO'S APPLICATION?

A. Yes, ABACO's number for depreciation includes an annual charge of $74,143 related to amortizing that resurrected amount of depreciation. In line with my recommendation, I am removing that amount from annual depreciation. In addition, I am removing the associated amount included in accumulated depreciation. Using the average of the total of accumulated depreciation at the end of 2018, $148,286, and at the end of 2019, $222,429, results in a decrease to accumulated depreciation of $185,358, which is shown on Exhibit PRS-3.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS RELATED TO DEPRECIATION?

A. Yes. ABACO is proposing to increase depreciation expense by $50,000 for a 1/6 amortization of an estimated $300,000 cost to remove its system if ABACO and Boyne do not renew their contract before it expires in 2027, as discussed in section 1c) of the contract between the two parties. This is an inappropriate adjustment, and I am removing the $50,000 from my recommended number for depreciation expense. This is also shown on Exhibit PRS-3.

Q. WHY IS ABACO'S PROPOSAL AN INAPPROPRIATE ADJUSTMENT?

A. This proposal would require ratepayers to pay in advance for an unlikely contingent event that may never happen.

Q. WHY DO YOU SAY IT IS AN UNLIKELY CONTINGENT EVENT?

A. It is contingent on Boyne and ABACO not reaching a new agreement. Both parties will be motivated to reach an agreement. ABACO will be motivated by the expense to remove the system and remediate the site if an agreement is not reached. Likewise, it would seem Boyne would be motivated to leave in place a functional, largely depreciated utility from which it is receiving service, rather than paying directly or indirectly for an entirely new system to be installed. Not to mention the inconvenience and lost revenue that would be associated with a changeover period. Also, ABACO is a regulated utility with an obligation to serve and it cannot just close down in 2027, without approval from the Commission.

Q. IS THIS AN EVENT THAT ABACO HOWEVER, HAS DEMONSTRATED IT EXPECTS TO HAPPEN BY HAVING RECORDED AN ASSOCIATED LIABILITY PREVIOUSLY?

A. No, ABACO has not accrued an associated liability. The 2027 date has not changed since ABACO came into compliance with PSC regulation. Nothing has changed to now suggest that they should be preparing for this possibility via ratepayer money when they were not doing so before. Given ABACO has an ongoing public utility obligation to serve, it cannot just stop serving in 2027 based on the contract. Since ABACO has now waived any right it may have had to contest this ongoing obligation, there is no reason to start accruing such a liability.

IV. ADJUSTMENTS TO DETERMINE RATE BASE

Q. ARE THERE ANY RATE BASE RELATED ADJUSTMENTS THAT YOU RECOMMEND?

A. Yes, I arrived at a rate base of $200,135 after making the following adjustments as shown on Exhibit PRS-5. The first adjustment is regarding unamortized rate case expense.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PLACING UNAMORTIZED RATE CASE EXPENSES IN RATE BASE?

A. It would be inequitable to ratepayers and create perverse incentives to the utility to permit unamortized rate case expense in rate base. These are necessary expenses for prosecuting a rate application as a regulated utility. However, regulatory, and legal professionals are hired specifically to represent the interests of the utility and its investors. By placing these unamortized professional fees into rate base, the utility is incented to spend more to promote its case. ABACO would then not only receive compensation to promote their viewpoint from those who may oppose it (e.g., ratepayers), but would also earn a return on those fees just like capital invested in utility plant used to serve customers. Ordinarily, utility regulators want to encourage cost containment. The Commission should consider balancing the necessity of incurring such expenses in conjunction with establishing the proper incentive to control these costs. Placing rate case expense into rate base would violate this balance and accordingly, rate case expense should not be allowed in rate base.

In addition, any amount placed into rate base and the associated return would not actually be amortized out of rates until the next rate case. So, not only would consumers continue to pay annual amortization expense each year even if the full amortization period has run, but they would also pay a return on the unamortized amount determined at the time of this rate case without recognition of the decline or complete elimination of that balance due to annual amortization between rate cases.

Q. WHAT IS YOUR NEXT ADJUSTMENT RELATED TO RATE BASE?

A. My next adjustment is related to working cash.

Q. WHAT IS WORKING CASH AND WHY IS IT INCLUDED IN RATE BASE?

A. If a utility, for example, were to initiate operations at the beginning of February 2021, it would incur various expenses necessary to provide service prior to collecting payment on the first bills sent out to customers. Ultimately, those expenses for February are recovered mostly in March but then the cash to pay March expenses is not received until sometime in April, and so on. In other words, there is theoretically an amount of operational expenses that the Company is always financing because it receives payment after the provision of utility service. As the utility is always financing, or "fronting" this money to handle the delay in receiving payment for service, they are entitled to earn a return on the amount being financed. However, utilities also may have some expenses that are not due for payment until after the associated revenue has been received to pay for them. For the working cash calculation, ABACO is using what I will call a modified "1/8 method." This method assumes that 45 days (1/8 of a year) passes between the payment by the utility for expenses and the receipt of the associated revenue from customers for a utility that bills monthly. Therefore, 1/8 or 12.5% is applied to the total O&M expenses and that figure is used for working cash. This is a common but generous assumption in that it assumes all expenses for the month are paid in full by the beginning of the month of service. The response to data request MCC-008 indicates that ABACO's billing cycle generally follows this presumed 45 days, so that 1/8 would be the right fraction to apply.

Q. YOU MENTIONED THAT ABACO USES A "MODIFIED" 1/8 METHOD TO CALCULATE WORKING CASH. WHAT DO YOU MEAN BY THAT?

A. On Schedule 38.5.141, Mr. Trogonoski applies 12.5% to his recommended number for operating expenses, however, he also applies that number to loan payments, rate case expense, property taxes, and other taxes and fees. Most of these additional items are not properly included.

Q. WHY DO YOU SAY THESE ITEMS ARE NOT PROPERLY INCLUDED IN THE WORKING CASH CALCULATION?

A. As mentioned, Mr. Trogonoski includes loan payments as an addition to working cash. Loan payments are paid after the fact as interest is accrued and paid in arrears. For a large utility paying on bonds semiannually, this is usually a source of working cash as they collect a significant portion of the payment in utility rates prior to making the cash payment to the lender. According to the ABACO loan agreements provided in response to MCC-011 (for the $105,000 in short term debt shown on Schedule 38.5.146), interest is payable quarterly. For example, interest is due April 1 for the previous three months. However, interest for January is collected in February and interest for February is collected in March, and then interest for March is collected on average mid-way through April. This means that the interest on this debt is on balance a source of working cash, as much of it is collected prior to payment being due.

Mr. Trogonoski includes rate case expense as a separate line item in his calculation but his rate case expense number of $55,579 is already included in his Operating Expenses number of $642,371, as can be seen on Schedule 38.5.156, so it is double counted for working cash.

Property taxes in Montana are generally payable five months after the six-month time period they apply to and are therefore a source of working cash. This is the case for ABACO (see attachment to MCC-009).

Mr. Trogonoski does indicate a net contribution of working cash from property taxes by including a property tax lag. However, he also applies 12.5% to the MCC and MPSC taxes, listed as Other Taxes and Fees, to calculate an increase to working cash. Like property taxes, MCC and MPSC taxes are remitted by the utility *after* receipt of payment from customers. This creates a supply of cost-free funds, not a need for working cash. Sections 69-1-223 and 69-1-402, MCA, require utilities to report gross revenue by calendar quarter and pay the MCC and MPSC taxes based on those revenues "within 30 days after the close of each calendar quarter."

While I do believe a properly modified 1/8 method could be used to calculate working cash, the Commission has indicated a preference for either a straight-forward fractional method applied to O&M expenses or a lead-lag study in calculating working cash. "It is preferable to use either a straight 1/12th approach-that doesn't consider non-operating expenses such as property taxes and the lead-lag characteristics thereof-or to commission a full lead-lag study." [19] Consequently, I am recommending a working cash

[19] MPSC Docket No. D2010.06.060, Order No. 7105f, ¶ 62.

amount of $53,487, calculated as 12.5% of my recommended O&M expense number as shown on Exhibit PRS-6.

Q. DO YOU HAVE ANY OTHER RATE BASE RELATED ADJUSTMENTS?

A. Yes, I also have an adjustment related to materials and supplies. Materials and supplies are commonly included in rate base. Utilities purchase and hence finance the acquisition of materials and supplies that are kept on hand for repairs and maintenance. In the amount ABACO includes for materials and supplies, prepaid expenses related to insurance, as indicated in the response to MCC-013 are also included. However, a full year of insurance expense is already accounted for with an application of 12.5% in the working cash calculation. Any more specific adjustment for prepaid insurance would need to be determined through a lead-lag study. This is also another modification to the 1/8 method. Accordingly, I am removing prepaid insurance from materials and supplies.

V. INCOME TAXES

Q. WHAT HAS BEEN YOUR RECOMMENDATION IN OTHER COMMISSION DOCKETS FOR THE TREATMENT OF INCOME TAXES FOR UTILITIES THAT ARE ORGANIZED AS PASS-THROUGH OR "DISREGARDED" ENTITIES FOR TAX PURPOSES?

A. I have recommended disallowance of income taxes from the revenue requirement because in those cases the utility itself does not incur a tax liability that has to be paid. Tax attributes (deductions, credits, income) of the utility are disregarded or "passed-through" to another ultimate taxpayer that may be the direct owner of the utility. Alternatively, the tax attributes may actually pass through multiple entities before reaching the taxable person or entity that will use those attributes in determining if they have taxable income, or a loss for tax purposes that may result in a tax refund. On Schedule 38.5.169, Statement J of its Application, ABACO states it is a limited liability company (LLC) and further states, "As such ABACO does not pay income taxes."

Q. DO YOU AGREE WITH MR. TROGONOSKI THAT WHETHER ABACO IS ALLOWED TO RECOVER INCOME TAXES SHOULD NOT DEPEND ON HOW THE UTILITY IS ORGANIZED?

A. No, I do not. How a utility is organized is central to the issue of whether there should be income tax recovery in utility rates. As the Montana Commission said in paragraph 85, Order No. 7105f, Docket No. 2010.06.060, "Therefore, the tax status, and tax liability, of the regulated utility (here a limited liability Company) is the only issue of concern. Individual members (or shareholders in the case of a corporation) are separate and distinct legal individuals from the business entities in which they have an ownership interest. As such, whether or not they incur tax liability on the monies which flow to them from the business entity is largely irrelevant to the question of whether the Commission should allow recovery for the regulated entity. The fact that members of pass-through entities (e.g. LLCs) are taxed differently than shareholders of C-Corporations inevitably creates certain inequities. However, it is the utility, not the individual members, which is subject to Commission regulation."

Q. WHAT WOULD YOUR RECOMMENDATION BE FOR INCOME TAX RECOVERY FOR UTILITIES LIKE NORTHWESTERN ENERGY OR MONTANA-DAKOTA UTILITIES THAT ARE ORGANIZED AS SUBCHAPTER C CORPORATIONS, GIVEN "CERTAIN INEQUITIES" MENTIONED ABOVE?

A. I would recommend that they receive recovery for income taxes in the revenue requirement. Subchapter C corporations as an entity pay taxes and are regulated by the Commission. Likewise, if a C Corporation were to report a loss for tax purposes, that loss could be offset against positive income in a prior and/or future tax year(s) potentially leading to a reduction in utility rates.

Q. WHILE THERE ARE SOME DIFFERENCES, DOES THIS TREATMENT CREATE AN INEQUITABLE SITUATION WHEREIN UTILITIES ORGANIZED AS C CORPORATIONS ARE MADE MORE ATTRACTIVE TO INVESTORS THAN UTILITIES ORGANIZED AS PASS THROUGH ENTITIES BECAUSE THEY RECEIVE COMPENSATION FOR INCOME TAXES WHEREAS PASS-THROUGH ENTITIES DO NOT?

A. No, that is not the case. Such ratemaking treatment generally maintains equity for utilities organized as different types of legal entities and for ratepayers as well. It is important to remember that when the Commission establishes a return on equity it is establishing an **after-tax** return on the equity funded portion of a utility's rate base. The after-tax return available to pay debt costs and to compensate equity holders is the same for a C Corporation that has received recovery for income taxes and for a pass-through entity that has not.

An oft-cited disadvantage of C Corporations is double taxation. C Corporations pay dividends that will be taxable to the recipients out of after-tax profits. Thus, profits are in effect taxed twice. For a pass-through entity, this is not the case. Profits will only be taxed as they reach the ultimate taxpayer unless one of the members of a pass-through entity happens to be a C Corporation that distributes dividends. *Figure A* serves to demonstrate this point using example numbers for illustrative purposes. It shows the revenue requirement for a utility if it receives income tax expense recovery in rates like a C Corporation compared to the revenue requirement if it is treated as a pass-through entity and does not receive income tax recovery.

Figure A - Comparison of Tax Treatments			
	C Corporation	Pass-through Entity	
Operating Revenues	$ 179,919	$ 169,934	Difference of $ 9,985
Other	3,900	3,900	
Total Revenues	$ 183,819	$ 173,834	
O&M Expenses	129,350	129,350	
Depreciation and Amort.	13,850	13,850	
Taxes Other Than Income	2,700	2,700	
Income Before Income Taxes	$ 37,919	$ 27,934	
Income Taxes	$ 9,985	$ -	Using flat 21% rate for illustration
Net Operating Income	$ 27,934	$ 27,934	
Rate Base	$ 325,000	$ 325,000	
Return on Rate Base	8.60%	8.60%	

Regardless of the tax treatment applied, the amount of net operating income or return on rate base to pay debt holders and equity holders is the same. The members of an LLC and stockholders of a C Corporation will both be taxed when they receive a distribution or dividend. The difference is that the revenue requirement is $9,985 higher for a C Corporation to allow for the taxes that it must pay as an entity (in the end it would be even a little higher because of the adjustment to the MCC/MPSC taxes for the higher revenue number). The members of a pass-through entity are not disadvantaged by such a tax treatment. In fact, if a pass-through entity were allowed recovery for income taxes that would simply result in an additional return on rate base and inequitable treatment of ratepayers. Given the example in *Figure A*, members of a pass-through entity would receive $37,919 or a 11.67% return versus 8.60% on rate base if income tax recovery were included in the revenue requirement. This is because the revenue requirement would be increased by $9,985 for a non-existent tax liability at the utility level. No money is owed to the taxing authorities by the utility. In such a scenario, equity holders in the utility are granted a windfall at the expense of ratepayers.

Q. ARE THERE OTHER REASONS THAT REGULATED UTILITIES THAT ARE ORGANIZED AS DISREGARDED ENTITIES FOR TAX PURPOSES SHOULD NOT RECEIVE RECOVERY FOR INCOME TAXES IN THE AUTHORIZED REVENUE REQUIREMENT?

A. Yes, there are other considerations as well that are highlighted by how ABACO proposes to include unnecessary income tax recovery in the calculated revenue requirement. In doing his income tax calculation, Mr. Trogonoski uses the current federal corporate income tax rate of 21% plus the Montana corporate tax rate of 6.75% for a combined total of

27.75%.[20] However, this would not be the appropriate rate to use for a calculation of income taxes. The proper number to use (*ignoring the impropriety of tax recovery for an LLC*) would be the weighted average effective income tax rate applied to the members of ABACO Energy Services, LLC. Mr. Trogonoski acknowledges this indirectly, when he says in his testimony on page 33 that "the individual income tax rates for the members of the LLC may be somewhat higher."

Whether higher or lower, to properly determine that weighted effective income tax rate would involve an examination of the income tax returns of each of the members. While some of that information may be relevant to this proceeding, the regulated entity in this proceeding is ABACO Energy Services, LLC, not its individual members. For any tax years that ABACO has passed through a loss or certain deductions, the members of ABACO have had a tax benefit, not the ratepayers. Should those members' tax rate(s) go down for some reason, the Commission could not easily initiate a proceeding to return any excess tax collections to rate payers as it previously did for Montana-Dakota Utilities and NWE.[21] As

[20] The actual combined rate under this scenario is 26.33% due to the deductibility of state income taxes for determining federal income tax liability, so the combined federal and state income tax rate is; (21.0%*(1-6.75%)) + 6.75% = 26.3325%. Also, AES, is a North Dakota limited liability company and its members appear to reside in North Dakota, so the use of the Montana Corp. tax rate also would be incorrect.

[21] *See* MPSC Docket Nos. D2018.4.24 & D2018.4.22.

Mr. Trogonoski says on page 31 of his testimony, "The members of the LLC have an actual or potential income tax liability on the income generated by the utility assets owned by ABACO." However, the Commission would never know whether there was an actual tax liability as those members are not regulated by the Commission.

Any tax recovery for the members of ABACO would go beyond what the shareholders in a utility organized as a C Corporation receive and would be for an income tax liability that may or may not even exist depending on each LLC member's tax situation. As this Commission has previously determined, it is fair and appropriate to not allow income tax recovery in rates for utilities organized as pass-through entities. Accordingly, I have removed income taxes from my calculation of the revenue requirement as shown on Exhibit PRS-1.

VI. CAPITAL STRUCTURE, ROE, and ROR

Q. HAVE YOU MADE ANY ADJUSTMENTS TO CAPITAL STRUCTURE AND RATE OF RETURN?

A. MCC testimony relating to capital structure and rate of return has been completed by Mr. David Garrett. The adjustments that I am making to revenue requirements are based on his testimony which recommends a 51% equity/49% debt capital structure, with a 5.77% cost of debt and a 9.0%

return on equity, resulting in an overall rate of return of 7.42%. This calculation and the resulting return on rate base are shown in Exhibit PRS-7.

VII. PROPANE SUPPLY & RATE DESIGN

Q. HOW DOES ABACO CURRENTLY ACQUIRE AND CHARGE CONSUMERS FOR PROPANE SUPPLY?

A. Page three of Mr. Tschider's testimony contains this description, "ABACO uses a competitive bid process to obtain its propane supply. Each year, ABACO sends a detailed RFP to six or seven propane suppliers soliciting bids. As its primary and single largest customer, Boyne is consulted about the bid results. ABACO then selects the best prices from the most dependable and reliable suppliers. Propane commodity costs are passed through to Boyne and other customers dollar-for-dollar without any markup by ABACO."

Q. ARE YOU SUGGESTING ANY CHANGES TO THIS PROCESS AT THIS TIME?

A. No. As indicated above, ABACO uses a competitive bid process to obtain its supply and passes through the commodity costs, as they should, to consumers on a dollar-for-dollar basis, and I am not recommending any changes. However, ABACO will need to file a new tariff annually to reflect the change in the commodity portion of rates charged to ratepayers.

Q. WHAT DO YOU PROPOSE FOR RATE DESIGN IN THIS CASE?

A. My proposal is that the rate design for ABACO be simplified to include a single fixed charge, a single volumetric pass-thru charge for the cost of propane per gallon, and a volumetric distribution charge per gallon of propane. In determining the fixed charge I used the same $6.50/mo. as used for NWE and Energy West Montana, Inc. The remaining revenue to be collected was allocated to the annual average 814,364 gallons of usage as shown on Mr. Trogonoski's Statement L. This resulted in a per gallon distribution rate of $0.54373.

Q. WHY DID YOU CHOOSE THAT APPROACH?

A. Without more specific information available it is necessary to choose an allocation between recovery in the fixed and volumetric portion of rates. A rate design with high customer charges is generally eschewed because of policy considerations. Reasons for this include the fact that bills will go up substantially for low-use consumers, and that consumers' incentive for conservation and ability to control their bills through usage decisions is muted.

Q. WHY DO YOU PROPOSE ONLY ONE NON-COMMODITY VOLUMETRIC RATE?

A. The separate O&M, and distribution volumetric rates that ABACO has been charging are based on a legacy from when ABACO acquired the propane system. As Mr. Trogonoski states on page 32 of his testimony, "This is consistent with the Company's rate design since the time ABACO acquired the assets from Northwestern Energy." There does not appear to be any justification for this approach, other than it is the way it has been done in the past. In my experience, that is an unusual separation of a volumetric charge that seems to add needless complication to the rate design and does not provide consumers with any meaningful information to inform their usage decisions.

Q. WHY ARE YOU NOT RECOMMENDING SEPARATE RESIDENTIAL AND COMMERCIAL RATES?

A. At this time there is no solid information on which to base a split between residential and commercial usage. ABACO is even unclear as to what it is recommending in this regard. Ms. Tschider's testimony on page six says, "It is ABACO's position that Boyne's load is a mixture of both commercial and residential, and therefore, should be allocated between the two classes." Further down that page she states, "The prior testimony, I believe, said that Boyne's use (commercial purposes) through that meter was about 70% and

Shoshone's use (residential purposes) through that meter was about 30%. Therefore, ABACO suggests the load delivered to the Shoshone meter should be billed in the same proportion to the two customer classes." However, Mr. Trogonoski states on page 34 of his testimony that "However, since ABACO does not know the percentage breakdown between commercial and residential usage for these volumes, I have treated all of the Boyne volume as commercial at this time." There are apparently two different recommendations regarding use of a 70/30 commercial/residential split.

Mr. Trogonoski's Allocated Cost of Service on Schedule 38.5.176 allocates costs but does not try to determine the source of those costs. It is designed to maintain the same proportional amount of revenue contribution, after his proposed increase, from each separate rate element as it currently exists. Typically, the foundation for allocated cost of service is the principle, that ideally, the "cost causer pays." No cost of service study has been conducted to determine any sort of identifiable cost causation by one group of ABACO ratepayers or another. Therefore, the distinction between residential and commercial customers is also a legacy of contract negotiations. If in the future a cost study is conducted, the results could be used to establish different rate classes for ABACO, if justified by cost causation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Deb Jonson, Executive Officer

Meet monthly to discuss AES organizations production, future goals, investments, and responsibilities.

Help to implement the strategic plan that has been set forth by AES.

Develop and maintain relationships built with our employees, customers, contractors and the surrounding area.

Established AES Website and also to keep it current

Monitor propane levels on a daily basis

Managing AES so we provide a drug-free workplace for our employees.

Prepare monthly statements for our customers.

Prepare and issue statements monthly via mail.

Monitor accounts to identify overdue payments.

Contact debtors to arrange debt payoffs.

Collaborate with credit collection agency.

Jeffrey D Jonson

CEO, Abaco Energy Services, LLC

Creating, communication and implementing AES vision, mission, and overall direction. Meet with other executives to determine if comp is in accordance with goals and policies.

Direct the organization financial goals, objective and budgets. Oversee the investment funds and manage associated risks, supervise cash management activities.

Meet regularly with senior AES leadership to make sure that decisions the organization needs are well-though out and timely. Work with team to spread ideas and direction thought AES until every employee understands their expected role and responsibilities for contribution.

Formulating and implementing the strategic plan that guides the direction of AES. Using the input of employees at every level of the organization to develop the strategic plan.

Overseeing the complete operation of AES in accordance with the direction established in the strategic plans.

Complete compliance forms and oversee the system maintenance, expansion, and compliance for safety and operations

Evaluating the success of AES or the lack thereof.

Maintain awareness of both the external and internal competitive landscape, customers, markets, new industry development and standards.

Represent AES in civic and professional association responsibilities and activities in the community, the state and at the national level. Develop and maintain relationships with other associations, industry, and government officials that are in the best interest of AES.

Negotiated contracts for AES

Purchase contracts

Supply contracts

Service contracts

Support Commercial Operation

Engineer

Daily Operations

Work with propane supplies

Negotiated RFP contract with suppliers

Work with Boyne on the RFP Contract

Work with IT, website, systems etc.

Monitor plant operation on a daily basis

Review and monitor accounting and financials

Work with attorneys on disputes, litigation, contracts, contracts, etc

Monitor propane market on a daily basis

Negotiate credit terms with customers

Mitigate inherent counterparty credit risk

Meet with customers and home owner boards

Create strategies to reduce deliver and credit risk from the suppliers

Sourced propane suppliers

Strengthened AES customer's relationship

Long term planning for the propane facilities

Stacy L. Tschider President of AES, responsibilities and duties. I spend approximately 10-15 hours a week.

Creating, communication and implementing AES vision, mission, and overall direction. Meet with other executives to determine if comp is in accordance with goals and policies.

Direct the organization financial goals, objective and budgets. Oversee the investment funds and manage associated risks, supervise cash management activities.

Meet regularly with senior AES leadership to make sure that decisions the organization needs are well-though out and timely. Work with team to spread ideas and direction thought AES until every employee understands their expected role and responsibilities for contribution.

Formulating and implementing the strategic plan that guides the direction of AES. Using the input of employees at every level of the organization to develop the strategic plan.

Overseeing the complete operation of AES in accordance with the direction established in the strategic plans.

Evaluating the success of AES or the lack thereof.

Maintain awareness of both the external and internal competitive landscape, customers, markets, new industry development and standards.

Represent AES in civic and professional association responsibilities and activities in the community, the state and at the national level. Develop and maintain relationships with other associations, industry, and government officials that are in the best interest of AES.

Negotiated contracts for AES

Purchase contracts

Supply contracts

Service contracts

Support Commercial Operation

Engineer

Daily Operations

Chief Financial Officer (CFO): Su-Lin Tschider

The CFO assumes a strategic role in the overall management of the company. The CFO has primary day-to-day responsibility for planning, implementing, managing and controlling all financial-related activities of the company. This includes direct responsibility for accounting, finance, forecasting, strategic planning, job costing, legal, property management, manage employees, contractors and consultants, deal analysis and negotiations, customer relationships, DOT and MT PSC compliance, and private and institutional financing.

The CFO also serves as the Controller who is responsible to prepare, present and report accurate and historical financial information, prepare tax information, and provide statistics to owners, banks, PSC, major customers, and other creditors. This position also includes the daily duties of the Accounting department. The accounts payable and accounts receivables processes are done by this person and maintained thru computer systems to complete these processes both in accounting, excel and utility billing software. This position prepares and analyzes the data to determine rates and invoices the agreed upon rates for customers and helps customers analyze their monthly usage.

This position is also Head of Customer Relations and Assistance who is responsible for answering the office phone calls from customers and emergency calls 24 hours a day.

The position is also head of Human Resources who is responsible for managing employees, contractors and consultants in addition to maintaining the complete employee benefits package and complying with employment laws, payroll processing, and employee training related to operations compliance and safety.

This position is head of Regulatory and Compliance/Safety for operations and maintenance requirements as required and is responsible for updated policies and procedures and recording adherence to at a minimum the following: the Operation and Emergency Manual, Operator Qualification, Public Awareness, FERC accounting, DOT annual reports, and drug testing administration and reporting. This position is responsible to adhere to regulated utility recordkeeping and policies.

Work with propane supplies

Negotiated RFP contract with suppliers

Work with Boyne on the RFP Contract

Work with IT, website, systems etc.

Monitor plant operation on a daily basis

Review and monitor accounting and financials

Work with attorneys on disputes, litigation, contracts, contracts, etc

Monitor propane market on a daily basis

Negotiate credit terms with customers

Mitigate inherent counterparty credit risk

Meet with customers and home owner boards

Create strategies to reduce deliver and credit risk from the suppliers

Sourced propane suppliers

Strengthened AES customer's relationship

Long term planning for the propane facilities

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is entered into on October 7, 2019 by the Montana Public Service Commission ("Commission") and ABACO Energy Services, L.L.C., a North Dakota limited liability company, 5359 Mica Dr., Bismarck, North Dakota 59803 ("ABACO") (the Commission and ABACO are referred to herein together as the "Parties") hereby enter into the following Settlement Agreement ("Agreement"):

Recitals

Whereas, on December 22, 2016, the Commission issued Order No. 7393c, in Commission Docket No. D2013.9.71 which, in relevant part, found that ABACO was a public utility pursuant to Mont. Code Ann. §69-3-101, and is subject to Commission jurisdiction;

Whereas, on January 20, 2017, ABACO filed a Petition for Judicial Review in Montana First Judicial District Court, Lewis and Clark County, bearing the cause number DDV 2017-57 (the "PJR"), and naming the Commission as Respondent, in which ABACO sought judicial review of the decision that ABACO is subject to Commission jurisdiction stated in Order No. 7393c;

Whereas, on January 18, 2018, the Commission filed a Complaint for Recovery of Civil Penalties for Violation of Commission Orders in Montana Fifth Judicial District Court, Madison County, bearing the cause number DV-29-2018-3 naming ABACO as defendant (the "Complaint") ;

Whereas, ABACO disputes the allegations of the Commission asserted in the Complaint and denies violation of any order of the Commission;

Whereas, the Parties have agreed to resolve the disputes stated in the PJR and the Complaint through voluntary settlement;

Now therefore, in consideration of the mutual promises contained herein, the Parties agree as follows:

Agreement

1. **Mutual Obligations of the Parties**. Within seven days of the date hereof, the Parties shall cause to be filed a Stipulation for dismissal with prejudice of the PJR in Montana First Judicial District Court, Lewis and Clark County Cause No. DDV 2017-57, as well as a Stipulation for dismissal with prejudice of the Complaint in Montana Fifth Judicial District Court, Madison County Cause No. DV-29-2018-3.

2. **Consent to Jurisdiction**. ABACO hereby acknowledges that it is a "public utility" as defined under Mont. Code Ann. §69-3-101 and is subject to the full power of supervision, regulation, and control of the Commission pursuant to Mont. Code Ann. §69-3-102.

3. **Rate Case Filing**. On or before June 1, 2020, ABACO shall file a general rate case with the Commission pursuant Mont. Code Ann. Title 69, Chapter 3, Part 3 for the purpose of setting Commission approved rates, tolls, and/or charges for any and all public utility services provided by ABACO.

4. **Mutual Release**. Subject to Paragraphs 2 and 3 of this Agreement, in consideration of the faithful performance of the terms of this Agreement, the Parties, for themselves, their successors, and assigns, do hereby relinquish, waive, release, acquit and forever discharge each other from any and all claims, disputes, actions, charges, contractual obligations, complaints, causes of action, rights demands, debts, damages or accountings of whatever nature, at law or in equity, known or unknown, asserted or not asserted, which they have now or may have in the future against one another based on the specific actions or events arising out of the PJR or Complaint.

5. **No Admission of Liability**. ABACO denies any and all liability associated with the Complaint and nothing contained herein shall constitute an admission or evidence of liability or wrongdoing on the part of ABACO in connection with the matters asserted in the Complaint. However, this Agreement may be introduced in any proceeding instituted for the purpose of enforcing its terms.

6. **Binding Effect**. This Agreement shall be binding upon and inure to the benefit of the heirs, successors, and assigns of ABACO.

7. **Non-Assignment**. A party's rights under this Agreement may not be assigned without the express written consent of the other party, which consent may be given only in accordance with applicable law.

8. **Additional Assurances**. The parties agree to execute any and all reasonable documents as may be reasonably necessary to carry out the terms, conditions, and obligations of this Agreement.

9. **Enforcement**. Nothing contained herein shall be construed to waive or limit the power and/or authority of the Commission to enforce the terms of this Agreement in any manner available under the law including, but not limited to, imposition of administrative penalties against ABACO pursuant to Mont. Code Ann. §§ 69-3-206 through -209.

10. **Modification**. This Agreement may not be modified except in writing signed by all Parties hereto.

11. **No Third Party Beneficiaries**. This Agreement is not for the benefit of any third party that is not referred to herein and shall not be deemed to give any right or remedy to any such third party. However, nothing contained in this Settlement Agreement shall be construed to waive

or limit any private right of action by any consumer, person, or by any governmental entity in Montana for claims unrelated to the matters at issue in this Agreement.

12. **Severability**. If any portions of this Agreement are held invalid and unenforceable, all remaining portions shall nevertheless remain valid and enforceable.

13. **Interpretation**. Each of the Parties has participated in the drafting and negotiation of this Agreement. Accordingly, this Agreement shall be deemed to have been drafted jointly by both Parties.

14. **Counterparts**. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be a counterpart and all of which together shall constitute one and the same document. Copies or facsimiles of signatures shall be deemed the equivalent of original signatures.

15. **Commission Approval**. The Commission, at an out-of-cycle, closed work session conducted during its regularly scheduled business meeting on October 1, 2019, approved the terms of this Agreement, and has delegated authority to staff attorney, Luke Casey, to execute this Agreement on its behalf.

16. **Representation of Authority**. Each person signing this Agreement hereby represents and warrants that he or she has the authority to bind the Party on behalf of which he or she has signed.

17. **Entire Agreement**. This Agreement contains the entire agreement of the Parties, and supersedes any and all prior and contemporaneous agreements, understandings, inducements or conditions, express or implied, concerning the same subject matter. No representations, oral or otherwise, express or implied, other than those contained herein have been made by any Party hereto. Each party specifically warrants that this Settlement Agreement is executed without reliance upon any statement or representation by any other party hereto, except as expressly stated herein.

Dated October 7, 2019

ABACO ENERGY SERVICES, L.L.C.

By:______________________________________

____

Its:____

MONTANA PUBLIC SERVICE COMMISSION

By:____
Luke Casey, Attorney

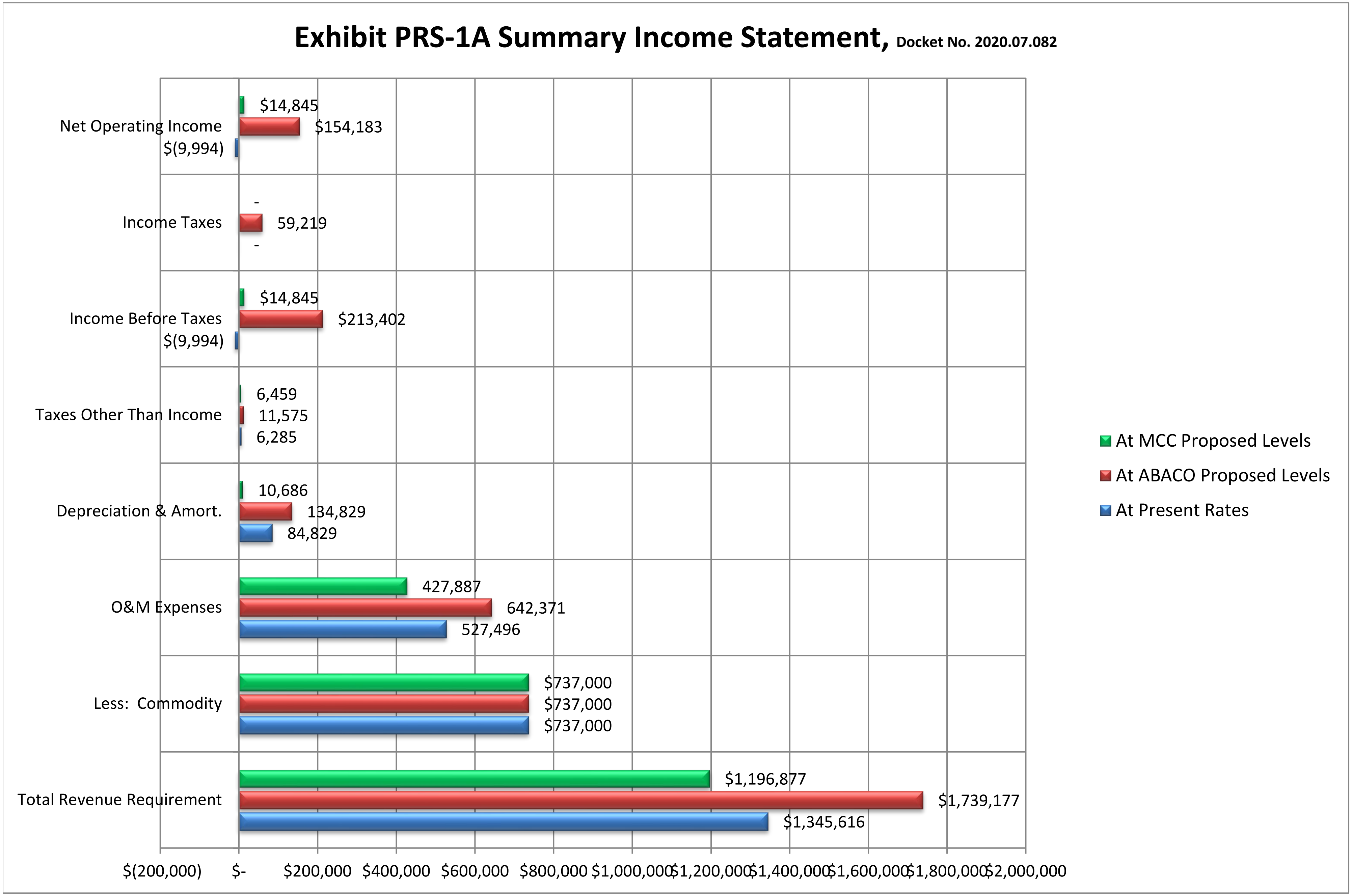
Exhibit PRS-1A Summary Income Statement, Docket No. 2020.07.082
Net Operating Income
$14,845
$154,183
$(9,994)
Income Taxes
-
59,219
-
Income Before Taxes
$14,845
$213,402
$(9,994)
Taxes Other Than Income
6,459
11,575
6,285
Depreciation & Amort.
10,686
134,829
84,829
O&M Expenses
427,887
642,371
527,496
Less: Commodity
$737,000
$737,000
$737,000
Total Revenue Requirement
$1,196,877
$1,739,177
$1,345,616
$(200,000)
$-
$200,000
$400,000
$600,000
$800,000
$1,000,000
$1,200,000
$1,400,000
$1,600,000
$1,800,000
$2,000,000
At MCC Proposed Levels
At ABACO Proposed Levels
At Present Rates

	ABACO Energy Services, LLC				Docket No. 2020.07.082
	Summary Income Statement				**Exhibit PRS-1**
	At Present Rates	At Proposed Rates	Proposed MCC Adj's	Proposed MCC Figures	
Operating Revenues	$ 608,616	$ 1,002,177	$ (542,300)	$ 459,877	
Commodity	737,000	737,000	-	737,000	
Total Revenue Requirement	$ 1,345,616	$ 1,739,177	$ (542,300)	$ 1,196,877	
Less: Commodity	$ 737,000	$ 737,000		$ 737,000	
O&M Expenses	527,496	642,371	(214,484)	427,887	
Depreciation & Amort.	84,829	134,829	(124,143)	10,686	
Taxes Other Than Income	6,285	11,575	(5,116)	6,459	
Income Before Taxes	$ (9,994)	$ 213,402	$ (198,557)	$ 14,845	
Income Taxes	-	59,219	(59,219)	-	
Net Operating Income	$ (9,994)	$ 154,183	$ (139,338)	$ 14,845	
Rate Base	$ 920,494	$ 920,494	$ (720,359)	$ 200,135	
Return on Rate Base	-1.086%	16.750%		7.417%	
Operating Revenue Change		$ 393,561		$ (148,739)	
Overall Percent Change in Oper. Rev's		64.66%		-24.44%	
MCC Proposed Rates : Fixed	$ 6.50	per meter per month			
Dist. Volumetric	$ 0.54373	per gallon of propane			

ABACO Energy Services, LLC		Docket No. 2020.07.082
Operating & Maintenance Expenses		**Exhibit PRS-2**
Company Proposed O&M Exp's in Application		$ 642,371
MCC proposed adj's		
Exclude non-incurred, speculative rent for Big Sky space		(19,800)
Eliminate pre-test year rate case expenses/4 yr. amort.		(30,579)
Remove regulatory cost		(3,000)
Adjust salaries and employer payroll taxes		(161,105)
Adjusted Total		$ 427,887

ABACO Energy Services, LLC			Docket No. 2020.07.082
Depreciation & Amortization			**Exhibit PRS-3**
	Company's Proposed Balance	MCC Proposed Adj's	MCC Proposed Amts.
Balance Sheet			
Accumulated Depreciation on physical plant 2018/2019 Avg.	$ 932,980		
Adjust out 2018/2019 Avg. Acc. Depr. for removed "Reg. Asset"		(185,357.50)	$ 747,622.00
Income Statement			
Depreciation/Amortization for 2019	$ 134,829		
Remove Depreciation on "Reg." Asset		(74,143.00)	
Remove contingent and speculative remediation cost		(50,000.00)	
			$ 10,686.00

ABACO Energy Services, LLC				Docket No. 2020.07.082	
Taxes Other Than Income				**Exhibit PRS-4**	
	Tax at Current Rates	Tax at Utility Proposed Rates	MCC Adj's	MCC Proposed Amts	
MCC Tax	$ 1,056.00	$ 2,209.00	$ (1,634.50)	$ 574.50	0.048%
PSC Tax	$ 3,498.00	$ 7,635.00	(3,481.84)	4,153.16	0.347%
Property Tax	1,731.00	$ 1,731.00		1,731.00	
Totals	$ 6,285.00	$ 11,575.00	$ (5,116.34)	$ 6,458.66	

	ABACO Energy Services, LLC				Docket No. 2020.07.082
	Rate Base				**Exhibit PRS-5**
			Company's Proposed Amts.	MCC Proposed Adj's	MCC Proposed Amts.
Utility Plant		Avg. 2018/2019	$ 1,750,074		
		Working Cash	$ 88,610		
		Materials and Supplies	$ 56,137		
		Unamortized Rate Case Expense	$ 111,158		
		Intangibles	$ 76,998		
	Remove "reg. asset" for recovered depreciation			(741,430)	
	Remove unamortized rate case expense			(111,158)	
	Remove prepaid insurance from matl's and Supplies			(18,004)	
	Adjustment to Working Cash			(35,123)	
Subtotal			$ 2,082,977	$ (905,715)	$ 1,177,262
Less:					
Accumulated Depreciation			$ 932,980		
	Adjust for Accumulated Depr. on "reg. asset"			(185,358)	747,622
Reserve for Intangibles			$ 59,061		59,061
Customer Plant			$ 170,444		170,444
Net Rate Base			$ 920,493	(185,358)	**$ 200,135**

ABACO Energy Services, LLC		Docket No. 2020.07.082	
Working Cash		**Exhibit PRS-6**	
O&M Expenses	$ 427,887		
Total	$ 427,887		
45/360	12.5%		
Gross Working Cash	$ 53,486		
Net Working Cash	$ 53,486		

ABACO Energy Services, LLC			Docket No. 2020.07.082	
Capital Structure & Rate of Return			**Exhibit PRS-7**	
Description	Ratio	Cost	Weighted Cost	
Equity	51.00%	9.00%	4.590%	
Debt	49.00%	5.77%	2.827%	
Overall ROR			7.417%	
MCC Proposed Rate Base			$ 200,135	
Required return on RB			$ 14,845	

ABACO Energy Services, LLC		Docket No. 2020.07.082	Exhibit PRS-8	
Rate Design				
Total Non-commodity Revenue Req.		$ 459,877		
$6.50 fixed charge revenue per yr.		$ 17,082		
Monthly charge for 219 meters		$ 6.50		
Remaining revenue to collect volumetrically		$ 442,795		
Average annual propane used in gallons per ABACO Statement L		814,364		
Distribution rate per gallon		$ 0.54373		

ABACO Energy Services, LLC		Docket No. 2020.07.082	Exhibit PRS-9							
	Calculations to Derive Hourly Compensation Rates for Calculating Annual Salaries Expense									
	Employee	Position	U.S. Bureau of Labor Statistics (BLS) Occupational Code and Desc.	ABACO Proposed Hourly Rate	Recommended Rate based on median, Bismarck May 2019, BLS Information	Inflation Adjustment[1]	Inflation adjusted hourly rate	ABACO Proposed Annual Amt.	MCC Recommended Annual Amt.	Adjustment to recommended annual amt.
	Stacy Tschider	President, LLC Member	11-1011: Chief Executives	$ 92.31	$ 58.79	$ 1.72	$ 60.51	$ 60,000	$ 39,330	
	Jeff Jonson	CEO, LLC Member	11-1021: General and Operations Managers	$ 92.31	39.55	$ 1.16	$ 40.71	$ 60,000	$ 26,459	
	Su-Lin(Melanie) Tschider	CFO, LLC Member	13-0000: Business and Financial Operations Occupations	$ 69.23	31.07	$ 0.91	$ 31.98	$ 90,000	$ 41,572	
	Deb Jonson	Exec. Officer, LLC Member	43-0000: Office and Administrative Support Occupations	$ 92.31	18.63	$ 0.54	$ 19.17	$ 60,000	$ 12,463	
Subtotal								$ 270,000	$ 119,825	$ (150,175)
Reduction to Employer FICA & Med[3]										$ (10,929)
Total Adjustment										$ (161,105)
2019 Total Salaries[2]	$ 345,098									
2019 Employer FICA & Med[2]	$ 25,115									

Footnotes:

[1] The inflation adjustment is derived from the latest BLS Employment Cost Index Summary which shows that inflation for wages and salaries for Civilian Workers for the 12 months ended June 2020 was 2.9% , then another 0.4% for the quarter ended September 2020. More recent data is not available so I am presuming another 0.4% inflation through December 2020. 2.9%*1.004*1.004 = 2.923%.

[2]Schedule 38.5.107.1

3The adjustment of $(150,175) reduces the 2019 salaries of $345,098 by (150,175/345,098) 43.52%. Employer payroll taxes are reduced by the same proportional amount.

ABACO Energy Services, LLC | Docket No. 2020.07.082 | **Exhibit PRS-10**

Summary of MCC Adjustments to Proposed Company Amounts

		Company Adj's	O&M Exp Adj's						Depr. Exp Adj's		Taxes Other Than Income Adj's			Int. Synch. Adj.	Inc. Taxes Adj.	
	Operating Revenue Adj.	N/A	Remove Big Sky potential rent	Rate Case Exp. Adj.	Remove Regulatory Cost	Adj. salaries and payroll taxes			Adj. out Reg. Asset Amort.	Remove contingent remediation amort.	Adjust MCC taxes	Adjust PSC Taxes	Adj. Prop. Taxes	N/A - No income taxes	Income Taxes-N/A for LLC	TOTAL
Operating Revenues	$ (542,300)															**$ (542,300)**
Other Income	$ -															-
Total Revenue Requirement	$ (542,300)															$ (542,300)
O&M Expenses			(19,800)	(30,579)	(3,000)	(161,105)										(214,484)
Depreciation & Amort.									(74,143)	(50,000)						(124,143)
Taxes Other Than Income											(1,634)	(3,482)	-			(5,116)
Income Before Income Taxes																$ (198,557)
Interest Synchronization																-
Income Taxes															(59,219)	(59,219)
Net Operating Income																**$ (139,338)**

Rate Base Adjustments

	Remove "Reg. asset"	Remove rate case exp.	Remove prepaid ins.	Adj. to working cash	Reduce Accum. Depr.	TOTAL
Rate Base	(741,430)	(111,158)	(18,004)	(35,123)	185,358	$ (720,357)
Return on Rate Base (ABACO used ROE)						-9.33%
9.33% change in return on MCC Rate Base						$ (18,678)
16.75% return on MCC RB adjustment						$ (120,660)
Total change in NOI						**$ (139,338)**
Operating Revenue Adj. from **Proposed** Company Rates						**$ (542,300)**
Overall Percent Change in Rates from **Proposed** Company Rates						-54.11%
Operating Revenue Adj. from **Present** Rates						$ (148,739)
Overall Percent Change in Rates from **Present** Rates						-24.44%

Bottom Up Approach Summary of Changes

	Net Operating Income	Income Taxes	Inc. Before Inc. Taxes	Taxes Other Than Inc.	Depr. Expense	O&M Exp's	Sum to Op. Rev. Adj.
9.33% change in return on MCC Rate Base	$ (18,678)	N/A for LLC					
16.75% return on MCC RB adjustment	(120,660)						
	$ (139,338)	$ (59,219)	$ (198,557)	$ (5,116)	$ (124,143)	$ (214,484)	**$ (542,300)**

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application of ABACO Energy Services, LLC, to Establish Service Rates and Terms of Service	))))	REGULATORY DIVISION DOCKET NO. 2020.07.082

DIRECT TESTIMONY OF

DAVID J. GARRETT

ON BEHALF OF

THE MONTANA CONSUMER COUNSEL

JANUARY 25, 2021

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LIST OF EXHIBITS

LIST OF APPENDICES

I. INTRODUCTION

Q. STATE YOUR NAME AND OCCUPATION.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting, PLLC.

Q. SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the commission, I formed Resolve Utility Consulting PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

Q. DESCRIBE THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. I am testifying on behalf of the Montana Consumer Counsel ("MCC") regarding the proposed return on equity and capital structure for ABACO Energy Services, LLC

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[1] Exhibit DJG-1.

("ABACO" or the "Company"). I address the direct testimony of Company witness John P. Trogonoski.

II. EXECUTIVE SUMMARY

A. Overview

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend the Commission authorize a return on equity of 9.0%. I also recommend the Commission impute a capital structure consisting of 49% debt and 51% equity. These recommendations equate to an overall, weighted average awarded rate of return of 7.42%, as shown in the figure below.[2]

Figure 1:
Recommended Weighted Average Awarded Return

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Debt	49.0%	5.77%	2.83%
Equity	51.0%	9.00%	4.59%
Total	100.0%		7.42%

These recommendations will be discussed in more detail later in my testimony.

[2] *See also* Exhibit DJG-17.

Q. EXPLAIN THE CONCEPT OF THE "WEIGHTED AVERAGE COST OF CAPITAL."

A. The term "cost of capital" refers to the weighted average cost of all types of components within a company's capital structure, including debt and equity. Determining the cost of debt is relatively straight-forward. Interest cost rates on bonds are contractual, derived, "embedded costs" that are generally calculated by dividing total interest payments by the book value of outstanding debt. In contrast, determining the cost of equity is more complex. Unlike the known contractual cost of debt, there is no explicit "cost" of equity; thus, the cost of equity must be estimated through various financial models. The overall weighted average cost of capital ("WACC") includes the cost of debt and the estimated cost of equity. It is a "weighted average," because it is based upon the Company's relative levels of debt and equity, or "capital structure." Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be closely estimated. The basic WACC equation used in regulatory proceedings is presented as follows:

Equation 1:
Weighted Average Cost of Capital

$$WACC = \left(\frac{D}{D+E}\right) C_D + \left(\frac{E}{D+E}\right) C_E$$

where:	$WACC$	=	*weighted average cost of capital*
	D	=	*book value of debt*
	C_D	=	*embedded cost of debt capital*
	E	=	*book value of equity*
	C_E	=	*market-based cost of equity capital*

Thus, the three components of the weighted average cost of capital include the following:

1. Cost of Equity
2. Cost of Debt
3. Capital Structure

The term "cost of capital" is necessarily synonymous with the "weighted average cost of capital," and the terms are used interchangeably throughout this testimony.

Q. DESCRIBE THE RELATIONSHIP BETWEEN THE COST OF EQUITY, REQUIRED RETURN ON EQUITY ("ROE"), EARNED ROE, AND AWARDED ROE.

A. While "cost of equity," "required ROE," "earned ROE," and "awarded ROE" are interrelated factors and concepts, they are all technically different from each other. The financial models presented in this case were created as tools for estimating the "cost of equity," which is synonymous to the "required ROE" that investors expect based on the amount of risk inherent in the equity investment. In other words, the cost of equity from the company's perspective equals the required ROE from the investor's perspective.

The "earned ROE" is a historical return that is measured from a company's accounting statements, and it is used to measure how much shareholders earned for investing in a company. A company's earned ROE is not the same as the company's cost of equity. For example, an investor who invests in a risky company may *require* a return on investment of 10%. If the company used the same estimates as the investor, then the company will estimate that its *cost* of equity is also 10%. If the company performs poorly and the investor *earns* a return of only 7%, this does not mean that the investor required only 7%, or that the investor will not still require a 10% return the following period. Thus, the cost of equity is not the same as the earned ROE.

Finally, the "awarded" return on equity is unique to the regulatory environment; it is the return authorized by a regulatory commission pursuant to legal guidelines. As discussed later in this testimony, the awarded ROE should be based on the utility's *cost* of equity. The relationship between the terms and concepts discussed thus far could be summarized in the following sentence: If the awarded ROE reflects a utility's cost of equity, then it should allow the utility to achieve an earned ROE that is sufficient to satisfy the required return of its equity investors. Thus, the "required" or "expected" return from an investor's standpoint is not simply what the investor wishes he could get. Likewise, the expected return of a utility investor has nothing to do with what the investor "expects" the ROE awarded by a regulatory commission to be. Rather, the expected return/cost of equity is estimated through objective, mathematical financial modeling based on risk.

Q. DESCRIBE THE COMPANY'S POSITION REGARDING ITS COST OF EQUITY IN THIS CASE.

A. In this case, Mr. Trogonoski proposes an awarded return on equity of 16.75% for the Company.[3] Mr. Trogonoski relies on the Discounted Cash Flow ("DCF") Model, and the Capital Asset Pricing Model ("CAPM").

[3] Direct Testimony of John P. Trogonoski, p. 6, lines 12-13.

Q. SUMMARIZE YOUR ANALYSES AND CONCLUSIONS REGARDING THE COMPANY'S COST OF EQUITY.

A. Analysis of an appropriate awarded ROE for a utility should begin with a reasonable estimation of the utility's cost of equity capital. In estimating the Company's cost of equity, I performed a cost of equity analysis on a proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, I evaluated the results of the two most common financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. Applying reasonable inputs and assumptions to these models indicates that the Company's estimated cost of equity is approximately 7.3%.[4]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. Pursuant to the legal and technical standards guiding this issue, the awarded ROE should be based on, or reflective of, the utility's cost of equity. As I explain in more detail below, the Company's estimated cost of equity is approximately 7.3%. However, these legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, in *Federal Power Commission v. Hope Natural Gas Co.*,[5] the U.S. Supreme Court ("Court" or "Supreme Court") found that, although the awarded return should be based on a utility's cost of capital, it also indicated that the "end result" should be just and

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[4] Exhibit DJG-12.

[5] *See Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). Here, the Court states that it is not mandating the various permissible ways in which the rate of return may be determined, but instead indicates that the end result should be just and reasonable. This is sometimes called the "end result" doctrine.

reasonable. If the Commission were to award ABACO a return equal to my estimated cost of equity of 7.3%, it would be accurate from a technical standpoint, and it would also significantly reduce the excess wealth transfer from ratepayers to shareholders that would otherwise occur if the Company's proposal were adopted. This is because when the awarded return unreasonably exceeds the cost of equity, it results in an excess wealth transfer from ratepayers to shareholders. Specifically, I recommend an awarded ROE of 9.0%.

Q. PLEASE EXPLAIN WHY YOUR AWARDED ROE RECOMMENDATION DOES NOT EXACTLY MATCH YOUR COST OF EQUITY ESTIMATE FOR ABACO.

A. The ratemaking concept of "gradualism," though usually applied from the customer's standpoint to minimize rate shock, could also be applied to shareholders. Although this is ABACO's first rate case, the awarded ROEs from the Commission for other utilities as well as the awarded ROEs from regulatory commissions in other jurisdictions, may likely have a bearing on the Commission's determination of a fair awarded ROE for ABACO. An awarded return as low as 7.3% in any current rate proceeding would represent a substantial change from the "status quo," which as I prove later in this testimony, involves awarded ROEs that clearly exceed market-based cost of equity for utilities. However, while generally reducing awarded ROEs for utilities would move awarded returns closer to market-based costs and reduce part of the transfer of excess wealth from ratepayers to shareholders, I believe it is advisable to do so gradually. One of the primary reasons the Company's cost of equity is so low is because the Company is a very low-risk asset. In general, utility stocks are low-risk investments because movements in their stock prices are relatively involatile. If the Commission were to make a significant, sudden change in the awarded ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile and would arguably be at odds with the *Hope* Court's "end result" doctrine. An awarded ROE of 9.0% represents a good balance between the Supreme Court's indications that awarded ROEs should be based on cost, while also recognizing that the end result must be reasonable under the circumstances. An awarded ROE of 9.0% also represents a gradual move toward the Company's market-based cost of equity, and it would be fair to the Company's shareholders because 9.0% is nearly 200 basis points above the Company's market-based cost of equity. Nonetheless, it is clear that the Company's proposed ROE of 16.75% is excessive and unreasonable, as further discussed below.

B. <u>Response to Mr. Trogonoski's Testimony</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROBLEMS YOU HAVE IDENTIFIED WITH MR. TROGONOSKI'S TESTIMONY.

A. Mr. Trogonoski proposes a return on equity of 16.75%.[6] Mr. Trogonoski's recommendations are based on the CAPM and DCF Model. However, several of his key assumptions and inputs to these models violate fundamental, widely accepted tenets in finance and valuation, while other assumptions and inputs are simply unrealistic. The key areas of concern are summarized as follows:

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[6] Direct Testimony of John P. Trogonoski, p. 3.

1. Terminal Growth Rate

In his DCF Model, Mr. Trogonoski's average long-term growth rate applied to the Company exceeds the long-term growth rate for the entire U.S. economy. In fact, Mr. Trogonoski's projected growth rates for his proxy companies are as high as 12.5%,[7] which is more than three times the projected U.S. GDP growth. It is a fundamental concept in finance that, in the long run, a company cannot fundamentally grow at a faster rate than the aggregate economy in which it operates; this is especially true for a regulated utility with a defined service territory. Thus, the results of Mr. Trogonoski's DCF Model are upwardly biased and are not reflective of current market conditions.

2. Equity Risk Premium

Mr. Trogonoski's estimate for the Equity Risk Premium ("ERP"), the single most important factor in estimating the cost of equity and a key input to the CAPM, is 11.86%.[8] The ERP is essentially the return required by investors in the stock market beyond the risk-free rate. Mr. Trogonoski's ERP estimate is significantly higher than the estimates reported by thousands of experts across the country.[9] Thus, Mr. Trogonoski's CAPM cost of equity estimate is overstated, unsupported, and unreasonable.

[7] 38.5.146.1 DCF Analysis.

[8] 38.5.146.2 CAPM Analysis.

[9] Exhibit DJG-10.

3. Small Size Premium

Mr. Trogonoski suggests that ABACO's size should somehow have an increasing effect on its cost of equity estimate.[10] Mr. Trogonoski adds a 391-basis point increase (3.91%) to his ROE recommendation for the size premium.[11] There have been many studies conducted over the past 40 years regarding the theory of whether companies of smaller size are associated with greater risk – and thus a greater cost of equity. Several studies show that since the postulation of the size effect phenomenon in the early 1980s, the size effect has essentially disappeared, or at the very least, is inconsistent and cyclical. Moreover, Mr. Trogonoski has not demonstrated how ABACO specifically should receive a nearly 400-basis point increase to its cost of equity estimate simply because it is a relatively smaller company. In my opinion, there should be no size effect adjustment to ABACO's estimated cost of equity in this case.

4. Capital Structure

Mr. Trogonoski proposes a capital structure consisting of 91% equity and 9% debt.[12] It is inconsistent to rely on key elements from the poxy group of utilities while completely ignoring the capital structures of the proxy group. This is because these factors are necessarily related. In this case, using the average debt ratio of the proxy group

[10] *See* Direct Testimony of John P. Trogonoski, pp. 35-42.

[11] 38.5.146.4 Small Size Premium.

[12] Testimony of John P. Trogonoski, p. 29, lines 5-10.

produces a far fairer and more reasonable rate of return than what is proposed by Mr. Trogonoski.

III. LEGAL STANDARDS AND THE AWARDED RETURN

Q. DISCUSS THE LEGAL STANDARDS GOVERNING THE AWARDED RATE OF RETURN ON CAPITAL INVESTMENTS FOR REGULATED UTILITIES.

A. In *Wilcox v. Consolidated Gas Co. of New York*, [13] the U.S. Supreme Court first addressed the meaning of a fair rate of return for public utilities. The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[14] Later in two landmark cases, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, [15] the Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

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[13] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[14] *Id*. at 48.

[15] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

In *Federal Power Commission v. Hope Natural Gas Company*, [16] the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses *but also for the capital costs of the business*. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

(Emphasis added). The cost of capital models I have employed in this case are in accordance with the foregoing legal standards.

Q. IS IT IMPORTANT THAT THE AWARDED RATE OF RETURN BE BASED ON THE COMPANY'S ACTUAL COST OF CAPITAL?

A. Yes, it is. The *Hope* Court makes it clear that the allowed return should be based on the actual cost of capital. Under the rate base rate of return model, a utility should be allowed to recover all its reasonable expenses, its capital investments through depreciation, and a return on its capital investments sufficient to satisfy the required return of its investors. The "required return" from the investors' perspective is synonymous with the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of return should be based on the actual cost of capital:

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital

[16] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944) (emphasis added).

> with the court's definition of legally required earnings appears clear.[17]

The models I have employed in this case closely estimate ABACO's true cost of equity. If the Commission sets the awarded return based on my recommended rate of return, it will comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of return significantly *higher* than the true cost of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to shareholders. As Dr. Morin notes:

> [I]f the allowed rate of return is greater than the cost of capital, capital investments are undertaken and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to the equity holders, and the stock price increases. In this case, the wealth transfer occurs from ratepayers to shareholders.[18]

Thus, it is important to understand that the *awarded* return and the *cost* of capital are different but related concepts. The two concepts are related in that the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. On the other hand, the two concepts are different in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Awarded returns are set through the regulatory process and may be influenced by a number of factors other than objective market drivers. The cost of capital, on the other hand, should be evaluated objectively and be closely tied to economic realities. In other words, the cost of capital is

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[17] A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 21 (The MIT Press 1984).

[18] Roger A. Morin, *New Regulatory Finance* 23-24 (Public Utilities Reports, Inc. 2006) (1994).

driven by stock prices, dividends, growth rates, and — most importantly — it is driven by risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the State's economy.

Q. DESCRIBE THE ECONOMIC IMPACT THAT OCCURS WHEN THE AWARDED RETURN STRAYS TOO FAR FROM THE U.S. SUPREME COURT'S COST OF EQUITY STANDARD.

A. As discussed further in the sections below, Mr. Trogonoski's recommended awarded ROE is much higher than ABACO's cost of capital based on objective market data. When the awarded ROE is set far above the *cost* of equity, it runs the risk of violating the U.S. Supreme Court's standards that the awarded return should be *based on the cost of capital*. If the Commission were to adopt the Company's position in this case, it would be permitting an excess transfer of wealth from ABACO's customers to Company shareholders. Moreover, establishing an awarded return that far exceeds the true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. This is yet another reason why it is crucial for regulators to focus on the target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions. Awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the true cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors. Regulators who rely too heavily on the awarded returns from other jurisdictions can create a cycle over time that bears little relation to the market-based cost of equity. In fact, this is exactly what we have observed since 1990 across the country in most jurisdictions.

Q. ILLUSTRATE AND COMPARE THE RELATIONSHIP BETWEEN AWARDED UTILITY RETURNS AND MARKET COST OF EQUITY SINCE 1990.

A. As shown in Figure 2 below, awarded returns for gas utilities have been above the average required market return since 1990.[19] Because utility stocks are consistently far less risky than the average stock in the marketplace, the cost of equity for utility companies is *less* than the market cost of equity. This is a fact, not an opinion. The graph below shows two trend lines. The top (solid blue) line is the average annual awarded returns since 1990 for U.S. regulated utilities. The bottom (orange dotted) line is the required market return over the same period. As discussed in more detail later in my testimony, the required market return is essentially the return that investors would require if they invested in the entire market. In other words, the required market return is essentially the cost of equity of the entire market. Since it is undisputed (even by utility witnesses) that utility stocks are less risky than the average stock in the market, then the utilities' actual cost of equity must be

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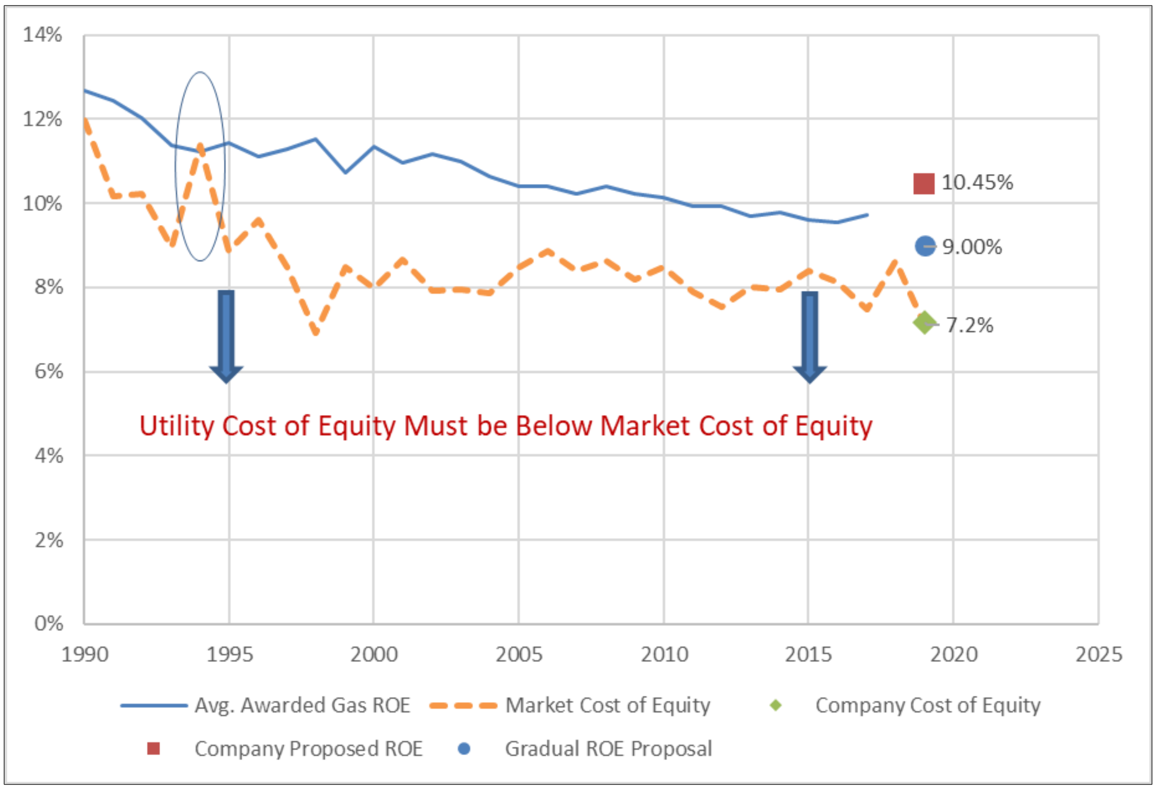
[19] *See* Exhibit DJG-14.

less than the market cost of equity.[20] Thus, awarded returns should generally be *below* the market cost of equity, since awarded returns are supposed to be based on true cost of equity.

Figure 2:
Awarded ROEs vs. Market Cost of Equity



Because utility stocks are less risky than the average stock in the market, utility cost of equity is *below* market cost of equity (the orange dotted line in this graph). However, as shown in this graph, awarded ROEs have been consistently *above* the market cost of equity for many years. As shown in the graph, since 1990 there was only one year in which the average awarded ROE was below the market cost of equity — 1994. In other words, 1994

[20] This fact can be objectively measured through a term called "beta," as discussed later in the testimony. Utility betas are less than one, which means utility stocks are less risky than the "average" stock in the market.

was the year that regulators awarded ROEs that were the closest to utilities' market-based cost of equity. In my opinion, when awarded ROEs for utilities are below the market cost of equity, they more closely conform to the standards set forth by *Hope* and *Bluefield* and minimize the excess wealth transfer from ratepayers to shareholders.

Q. HAVE OTHER ANALYSTS COMMENTED ON THIS NATIONAL PHENOMENON OF AWARDED ROES EXCEEDING THE MARKET-BASED COST OF EQUITY FOR UTILITIES?

A. Yes. In his article published in Public Utilities Fortnightly in 2016, Steve Huntoon observed that even though utility stocks are less risky than the stocks of competitive industries, utility stocks have nonetheless outperformed the broader market.[21] Specifically, Huntoon notes the following three points which lead to a problematic conclusion:

> 1. Jack Bogle, the founder of Vanguard Group and a Wall Street legend, provides rigorous analysis that the long-term total return for the broader market will be around 7 percent going forward. Another Wall Street legend, Professor Burton Malkiel, corroborates that 7 percent in the latest edition of his seminal work, *A Random Walk Down Wall Street*.
>
> 2. Institutions like pension funds are validating [the first point] by piling on risky investments to try and get to a 7.5 percent total return, as reported by the Wall Street Journal.
>
> 3. Utilities are being granted returns on equity around 10 percent.[22]

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[21] Steve Huntoon, "Nice Work If you can Get It," Public Utilities Fortnightly (Aug. 2016).

[22] *Id*.

In a follow-up article analyzing and agreeing with Mr. Huntoon's findings, Leonard Hyman and William Tilles found that utility equity investors expect about a 7.5% annual return.[23]

Other scholars have also observed that awarded ROEs have not appropriately tracked with declining interest rates over the years, and that excessive awarded ROEs have negative economic impacts. In a 2017 white paper, Charles S. Griffey stated:

> The "risk premium" being granted to utility shareholders is now higher than it has ever been over the last 35 years. Excessive utility ROEs are detrimental to utility customers and the economy as a whole. From a societal standpoint, granting ROEs that are higher than necessary to attract investment creates an inefficient allocation of capital, diverting available funds away from more efficient investments. From the utility customer perspective, if a utility's awarded and/or achieved ROE is higher than necessary to attract capital, customers pay higher rates without receiving any corresponding benefit.[24]

It is interesting that both Mr. Huntoon and Mr. Griffey use the word "sticky" in their articles to describe the fact that awarded ROEs have declined at a much slower rate than interest rates and other economic factors resulting in a decline in capital costs and expected returns on the market. It is not hard to see why this phenomenon of sticky ROEs has occurred. Because awarded ROEs are often based primarily on a comparison with other awarded ROEs around the country, the average awarded returns effectively fail to adapt to true market conditions, and regulators seem reluctant to deviate from the average. Once utilities

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[23] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

[24] Charles S. Griffey, "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns," White Paper (February 2017).

and regulatory commissions become accustomed to awarding rates of return higher than market conditions actually require, this trend becomes difficult to reverse. Nevertheless, the fact is that utility stocks are *less risky* than the average stock in the market, and thus, awarded ROEs should be less than the expected return on the market. However, that is rarely the case. "Sooner or later, *regulators may see the gap between allowed returns and cost of capital*."[25]

Q. SUMMARIZE THE LEGAL STANDARDS GOVERNING THE AWARDED ROE ISSUE.

A. The Commission should strive to move the awarded return to a level more closely aligned with the Company's actual, market-derived cost of capital while keeping in mind the following legal principles:

1. Risk is the most important factor when determining the awarded return. The awarded return should be commensurate with those on investments of corresponding risk.

The legal standards articulated in *Hope* and *Bluefield* demonstrate that the Court understands one of the most basic, fundamental concepts in financial theory: the more (less) risk an investor assumes, the more (less) return the investor requires. Since utility stocks are very low risk, the return required by equity investors should be relatively low. I have used financial models in this case to closely estimate ABACO's cost of equity, and these financial models account for risk. The public utility industry is one of the least risky

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[25] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016) (emphasis added).

industries in the entire country. The cost of equity models confirm this fact in that they produce relatively low cost of equity results. In turn, the awarded ROE in this case should reflect the fact that ABACO is a low-risk firm.

2. The awarded return should be sufficient to assure financial soundness under efficient management.

Because awarded returns in the regulatory environment have not closely tracked market-based trends and commensurate risk, utility companies have been able to remain more than financially sound, perhaps despite management inefficiencies. In fact, the transfer of wealth from ratepayers to shareholders has been so far removed from actual cost-based drivers that even under relatively inefficient management a utility could remain financially sound. Therefore, regulatory commissions should strive to set the awarded return for a regulated utility at a level based on accurate market conditions to promote prudent and efficient management and minimize economic waste.

IV. GENERAL CONCEPTS AND METHODOLOGY

Q. DISCUSS YOUR APPROACH TO ESTIMATING THE COST OF EQUITY IN THIS CASE.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. These models are the Discounted Cash Flow Model ("DCF Model") and the Capital Asset Pricing Model ("CAPM"). The specific inputs and calculations for these models are described in more detail below.

Q. PLEASE EXPLAIN WHY MULTIPLE MODELS ARE USED TO ESTIMATE THE COST OF EQUITY.

A. The models used to estimate the cost of equity attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. PLEASE DISCUSS THE BENEFITS OF CHOOSING A PROXY GROUP OF COMPANIES IN CONDUCTING COST OF CAPITAL ANALYSES.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly traded company. There are advantages, however, to conducting cost of capital analysis on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly traded firms, such as stock prices and dividends.

Q. DESCRIBE THE PROXY GROUP YOU SELECTED IN THIS CASE.

A. In this case, I chose to use the same proxy group used by Mr. Trogonoski. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.[26] By using the same proxy group, we can remove a relatively insignificant variable from the equation and focus on the primary factors driving the Company's cost of equity estimate in this case.

V. <u>RISK AND RETURN CONCEPTS</u>

Q. DISCUSS THE GENERAL RELATIONSHIP BETWEEN RISK AND RETURN.

A. Risk is among the most important factors for the Commission to consider when determining the allowed return. Thus, it is necessary to understand the relationship between risk and return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

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[26] *See* Exhibit DJG-2.

Q. DISCUSS THE DIFFERENCES BETWEEN FIRM-SPECIFIC RISK AND MARKET RISK.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[27] There are several other types of firm-specific risks, including: (1) "financial risk" — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" — the risk that a firm will default on its debt securities; and (3) "business risk" — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company. While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[28]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During that year, Enron Corp.'s stock fell from $80 per share to less than $1 per share, and the company filed bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would have lost his or her entire investment by the end of the year due to assuming

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[27] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62-63 (3rd ed., John Wiley & Sons, Inc. 2012).

[28] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because his portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various *market* risk factors that occurred that year, including the terrorist attacks on September 11th, which affected all stocks in the market. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

Q. CAN INVESTORS EASILY MINIMIZE FIRM-SPECIFIC RISK?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[29] If someone irrationally invested all their funds in one firm, they would be exposed to all the firm-specific risk *and* the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can essentially eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio

[29] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179-80 (3rd ed., South Western Cengage Learning 2010).

of just one or a few stocks. Thus, any firm-specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[30]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[31] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

Q. IS IT WELL-KNOWN AND ACCEPTED THAT, BECAUSE FIRM-SPECIFIC RISK CAN BE EASILY ELIMINATED THROUGH DIVERSIFICATION, THE MARKET DOES NOT REWARD SUCH RISK THROUGH HIGHER RETURNS?

A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that

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[30] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

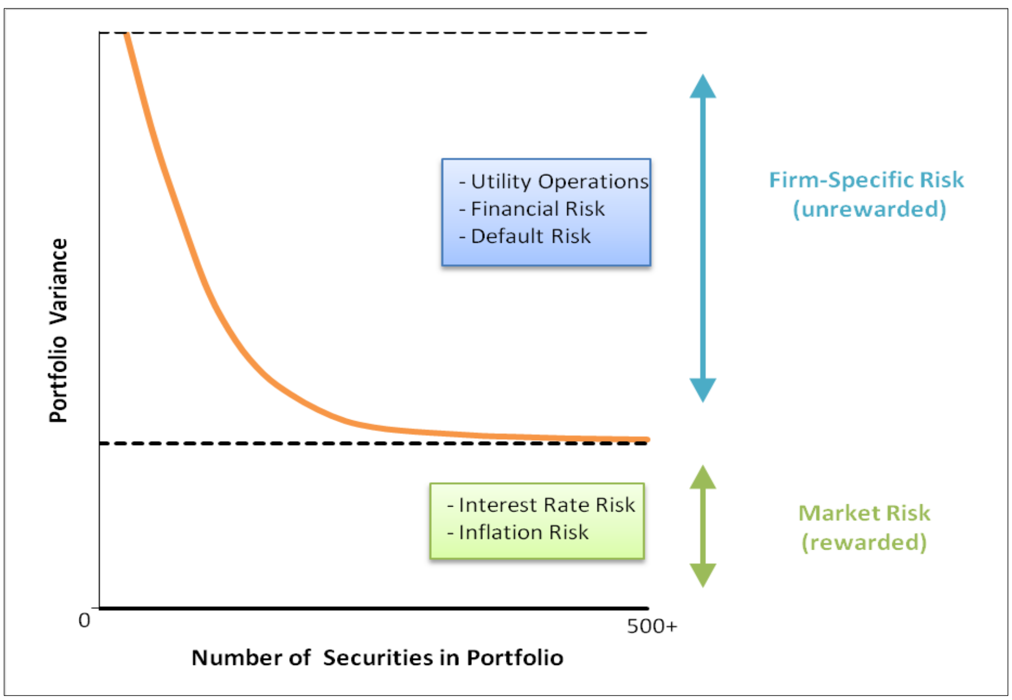
[31] *Id*.

market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing:

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).[32]

These important concepts are illustrated in figure 3 below. Some form of this figure is found in many financial textbooks.

Figure 3:
Effects of Portfolio Diversification



[32] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus the primary type of risk the Commission should consider when determining the allowed return in this case.

Q. DESCRIBE HOW MARKET RISK IS MEASURED.

A. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[33] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk, such that if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The

[33] *Id*. at 180-81.

beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[34]

Q. ARE PUBLIC UTILITIES CHARACTERIZED AS DEFENSIVE FIRMS THAT HAVE LOW BETAS, LOW MARKET RISK, AND ARE RELATIVELY INSULATED FROM OVERALL MARKET CONDITIONS?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[35] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[36] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[37]

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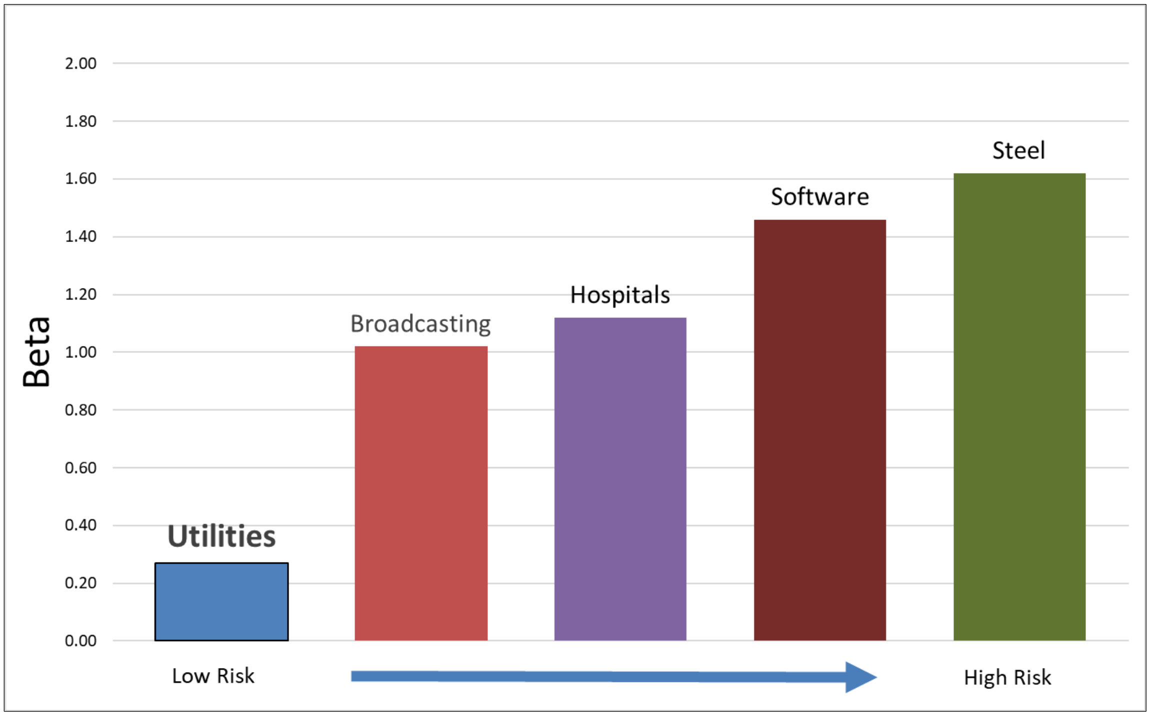
[34] Though it will be discussed in more detail later, Exhibit DJG-8 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

[35] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

[36] *Id*. at 383.

[37] *See* Betas by Sector (US) available at http://pages.stern.nyu.edu/~adamodar/ (2018). (After clicking the link, click "Data" then "Current Data" then "Risk / Discount Rate" from the drop-down menu, then "Total Beta by Industry Sector"). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very

Figure 4:
Beta by Industry



The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not widely fluctuate. So, while it is recognized and accepted that utilities are defensive firms that experience little market risk and are relatively insulated from market conditions, this fact should also be appropriately reflected in the Company's awarded return.

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low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") MODEL.

A. The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model are discussed in more detail in Appendix A. For this case, I chose to use the Quarterly Approximation DCF Model.

Q. DESCRIBE THE INPUTS TO THE DCF MODEL.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

C. Stock Price

Q. HOW DID YOU DETERMINE THE STOCK PRICE INPUT OF THE DCF MODEL?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[38] Analysts sometimes rely on average stock prices for longer periods (e.g.,

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[38] Exhibit DJG-3.

60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[39] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. WHY DID YOU USE A 30-DAY AVERAGE FOR THE CURRENT STOCK PRICE INPUT?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding, there is a significant length of time from when an application is filed, and testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model that is ultimately used to set rates for several years, especially if a stock is experiencing

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[39] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 357 (3rd ed., South Western Cengage Learning 2010). The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[40]

D. Dividend

Q. DESCRIBE HOW YOU DETERMINED THE DIVIDEND INPUT OF THE DCF MODEL.

A. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share. I obtained the most recent quarterly dividend paid for each proxy company.[41] The Quarterly Approximation DCF Model assumes that the company increases its dividend payments each quarter. Thus, the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. This expression could be described as the dividend quarterly growth rate, where the term "g" is the growth rate and the exponential term "0.25" signifies one quarter of the year.

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[40] Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[41] Exhibit DJG-4. Nasdaq Dividend History, available at http://www.nasdaq.com/quotes/dividend-history.aspx.

Q. DOES THE QUARTERLY APPROXIMATION DCF MODEL RESULT IN THE HIGHEST COST OF EQUITY IN THIS CASE RELATIVE TO OTHER DCF MODELS, ALL ELSE HELD CONSTANT?

A. Yes. The DCF Model I employed in this case results in a higher DCF cost of equity estimate than the annual or semi-annual DCF Models due to the quarterly compounding of dividends inherent in the model. In essence, the Quarterly Compounding DCF Model I used results in the *highest* cost of equity estimate, all else held constant.

Q. ARE THE STOCK PRICE AND DIVIDEND INPUTS FOR EACH PROXY COMPANY A SIGNIFICANT ISSUE IN THIS CASE?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. Trogonoski, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be conducted on utilities. The differences between my DCF Model and Mr. Trogonoski's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

E. Growth Rate

Q. SUMMARIZE THE GROWTH RATE INPUT IN THE DCF MODEL.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input must be estimated. As a result, the growth rate is often the most contentious DCF input in utility rate cases. The DCF used in utility rate cases is essentially based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Thus, the growth rate term in the constant growth DCF model is often called the "constant," "stable," or "terminal" growth rate. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the terminal growth rate is less complex. The growth term of the DCF Model is one of the most important, yet apparently most misunderstood aspects of cost of equity estimations in utility regulatory proceedings. Therefore, I have devoted a more detailed explanation of this issue in the following sections, which are organized as follows:

(1) The Various Determinants of Growth

(2) Reasonable Estimates for Long-Term Growth

(3) Quantitative vs. Qualitative Determinants of Utility Growth: Circular References, "Flatworm" Growth, and the Problem with Analysts' Growth Rates

(4) Growth Rate Recommendation

1. <u>The Various Determinants of Growth</u>

Q. DESCRIBE THE VARIOUS DETERMINANTS OF GROWTH.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on long-term growth rates, which are discussed in the following section.

1. Historical Growth

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth. In general, however, revenue growth tends to be more consistent and predictable than earnings growth because it is less likely to be influenced by accounting adjustments.[42]

2. Analyst Growth Rates

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. A more detailed discussion of analyst growth rates, including the problems with using them in the DCF Model to estimate utility cost of equity, is provided in a later section.

3. Fundamental Determinants of Growth

Fundamental growth determinants refer to firm-specific financial metrics that arguably provide better indications of near-term sustainable growth. One such metric for

[42] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

fundamental growth considers the return on equity and the retention ratio. The idea behind this metric is that firms with high ROEs and retention ratios should have higher opportunities for growth.[43]

Q. DID YOU USE ANY OF THESE GROWTH DETERMINANTS IN YOUR DCF MODEL?

A. No. Primarily, the growth determinants discussed above would provide better indications of short to mid-term growth for firms with average to high growth opportunities. However, utilities are mature, low-growth firms. While it may not be unreasonable on its face to use any of these growth determinants for the growth input in the DCF Model, we must keep in mind that the stable growth DCF Model considers only *long-term* growth rates, which are constrained by certain economic factors, as discussed further below.

2. <u>Reasonable Estimates for Long-Term Growth</u>

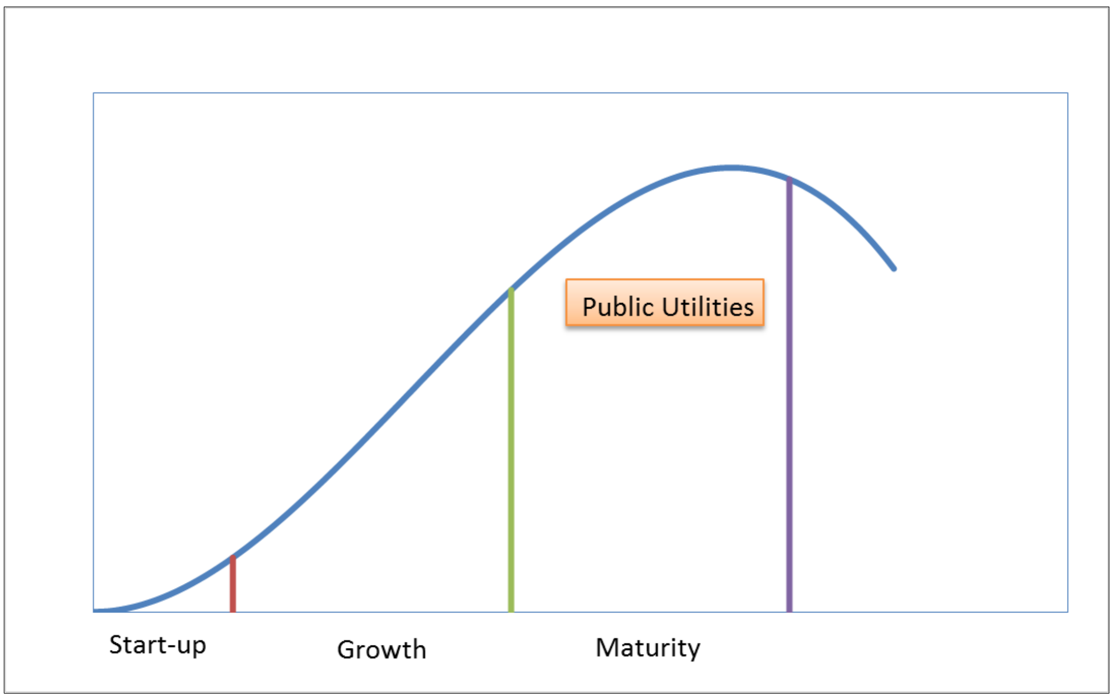
Q. DESCRIBE WHAT IS MEANT BY LONG-TERM GROWTH.

A. In order to make the DCF a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being constant. However, it is not necessary to use multi-stage DCF

[43] *Id*. at 291-292.

Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "terminal," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by the customer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

Figure 5:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate. Because utilities are in their maturity stage, their real growth opportunities are primarily limited to the population growth within their defined service territories, which is usually less than 2%.

Q. IS IT TRUE THAT THE TERMINAL GROWTH RATE CANNOT EXCEED THE GROWTH RATE OF THE ECONOMY, ESPECIALLY FOR A REGULATED UTILITY COMPANY?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[44] Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Aswath Damodaran:

> "If a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[45]

Other scholars have similarly found:

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[44] *See generally* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[45] *Id*.

> "The growth rate assumed in calculating the terminal value is a compound growth rate *in perpetuity*, which is a very long time. At a growth rate [exceeding GDP] compounded annually, the company's revenues would soon exceed the gross domestic product (GDP) of the United States and eventually that of the world. Long-term growth rates exceeding the real growth in GDP plus inflation are generally not sustainable. Most analysts use more conservative growth rates in calculating the terminal value."[46]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is *less* than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross domestic product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.9%, which includes an inflation rate of 2%.[47] For mature companies in mature industries, such as utility companies, the terminal growth rate will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, ABACO's terminal growth rate is realistically between 2% and 4%.

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[46] Shannon P. Pratt and Roger J. Grabowski, *Cost of Capital: Applications and Examples* 1195 (5th ed., John Wiley & Sons, Inc. 2014).

[47] Congressional Budget Office – The 2019 Long-Term Budget Outlook p. 54, https://www.cbo.gov/publication/55331.

Q. IS IT REASONABLE TO ASSUME THAT THE TERMINAL GROWTH RATE WILL NOT EXCEED THE RISK-FREE RATE?

A. Yes. In the long term, the risk-free rate will converge on the growth rate of the economy. For this reason, financial analysts sometimes use the risk-free rate for the terminal growth rate value in the DCF model.[48] I discuss the risk-free rate in further detail later in this testimony.

Q. PLEASE SUMMARIZE THE VARIOUS LONG-TERM GROWTH RATE ESTIMATES THAT CAN BE USED AS THE TERMINAL GROWTH RATE IN THE DCF MODEL.

A. The reasonable long-term growth rate determinants are summarized as follows:

1. Nominal GDP Growth
2. Real GDP Growth
3. Inflation
4. Current Risk-Free Rate

Any of the foregoing growth determinants could provide a reasonable input for the terminal growth rate in the DCF Model for a utility company, including ABACO. In general, we should expect that utilities will, at the very least, grow at the rate of projected inflation. However, the long-term growth rate of any U.S. company, especially utilities, will be constrained by nominal U.S. GDP growth.

[48] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 307 (3rd ed., John Wiley & Sons, Inc. 2012).

3. Qualitative Growth: The Problem with Analysts' Growth Rates

Q. DESCRIBE THE DIFFERENCES BETWEEN "QUANTITATIVE" AND "QUALITATIVE" GROWTH DETERMINANTS.

A. Assessing "quantitative" growth simply involves mathematically calculating a historic metric for growth (such as revenues or earnings) or calculating various fundamental growth determinants using various figures from a firm's financial statements (such as ROE and the retention ratio). However, any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve a sustainable growth in earnings. Therefore, it is important to begin the analysis of ABACO's growth rate with this simple, qualitative question: How is this regulated utility going to achieve a sustained growth in earnings? If this question were asked of a competitive firm, there could be several answers depending on the type of business model, such as launching a new product line, franchising, rebranding to target a new demographic, or expanding into a developing market. Regulated utilities, however, cannot engage in these potential growth opportunities.

Q. WHY IS IT ESPECIALLY IMPORTANT TO EMPHASIZE REAL, QUALITATIVE GROWTH DETERMINANTS WHEN ANALYZING THE GROWTH RATES OF REGULATED UTILITIES?

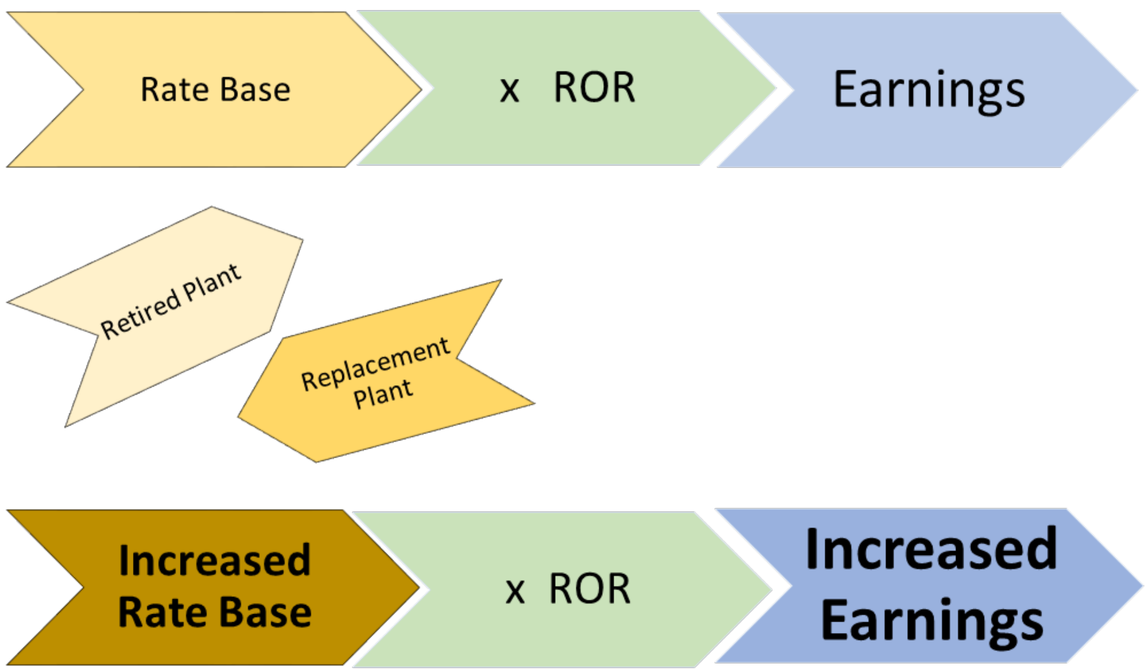
A. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective. These two factors are (1) rate base and (2) the awarded ROE. I will discuss each factor further below.

It is important to keep in mind that the ultimate objective of this analysis is to provide a foundation upon which to base the fair rate of return for the utility. Thus, we should strive to ensure that each individual component of the financial models used to estimate the cost of equity are also "fair." If we consider only quantitative growth determinants, it may lead to projected growth rates that are overstated and ultimately unfair, because they result in inflated cost of equity estimates.

Q. HOW DOES RATE BASE RELATE TO GROWTH DETERMINANTS FOR UTILITIES?

A. Under the rate base rate of return model, a utility's rate base is multiplied by its awarded rate of return to produce the required level of operating income. Therefore, increases to rate base generally result in increased earnings. Thus, utilities have a natural financial incentive to increase rate base. In short, utilities have a financial incentive to increase rate base regardless of whether such increases are driven by a corresponding increase in demand. Under these circumstances, utilities have been able to increase their rate bases by a far greater extent than what any concurrent increase in demand would have required. In other words, utilities "grew" their earnings by simply retiring old assets and replacing them with new assets. If the tail of a flatworm is removed and regenerated, it does not mean the flatworm actually grew. Likewise, if a competitive, unregulated firm announced plans to close production plants and replace them with new plants, it would not be considered a real determinant of growth unless analysts believed this decision would directly result in increased market share for the company and a real opportunity for sustained increases in revenues and earnings. In the case of utilities, the mere replacement of old plant with new plant does not increase market share, attract new customers, create franchising opportunities, or allow utilities to penetrate developing markets, but may result in short-term, quantitative earnings growth. This "flatworm growth" in earnings was merely the quantitative byproduct of the rate base rate of return model, and not an indication of real, fair, or qualitative growth. The following diagram illustrates this concept.

Figure 6:
Analysts' Earnings Growth Projections: The "Flatworm Growth" Problem

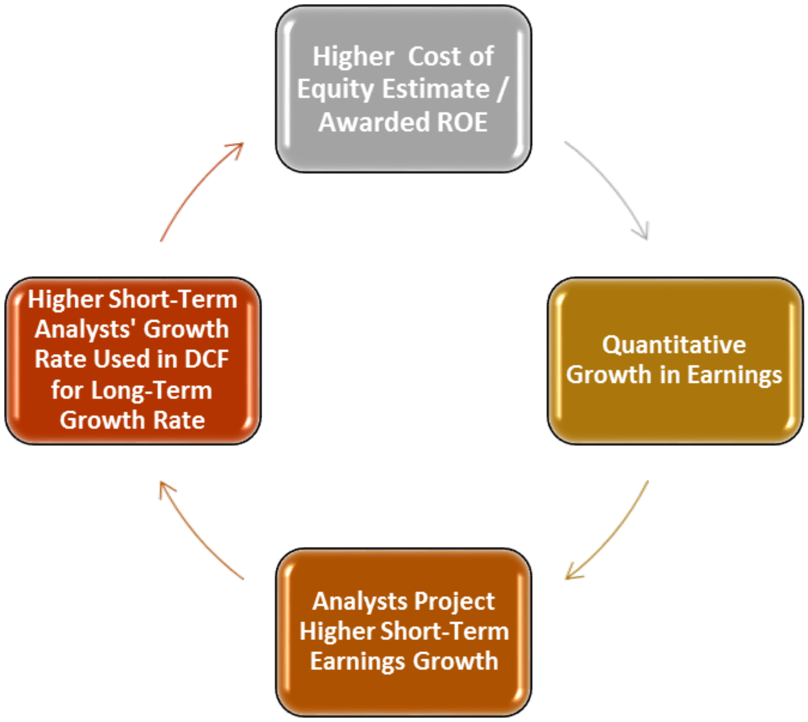


Of course, utilities might sometimes add new plant to meet a modest growth in customer demand. However, as the foregoing discussion demonstrates, it would be more appropriate to consider load growth projections and other qualitative indicators, rather than mere increases to rate base or earnings, to attain a fair assessment of growth.

Q. PLEASE DISCUSS THE OTHER WAY IN WHICH ANALYSTS' EARNINGS GROWTH PROJECTIONS DO NOT PROVIDE INDICATIONS OF FAIR, QUALITATIVE GROWTH FOR REGULATED UTILITIES.

A. If we give undue weight to analysts' projections for utilities' earnings growth, it will not provide an accurate reflection of real, qualitative growth because a utility's earnings are heavily influenced by the ultimate figure that all this analysis is supposed to help us estimate: the awarded return on equity. This creates a circular reference problem or feedback loop. In other words, if a regulator awards an ROE that is above market-based cost of capital (which is often the case, as discussed above), this could lead to higher short-term growth rate projections from analysts. If these same inflated, short-term growth rate estimates are used in the DCF Model (and they often are by utility witnesses), it could lead to higher awarded ROEs; and the cycle continues, as illustrated in the following figure:

Figure 7:
Analysts' Earnings Growth Projections: The "Circular Reference" Problem



Therefore, it is not advisable to simply consider the quantitative growth projections published by analysts, as this practice will not necessarily provide fair indications of real utility growth.

Q. ARE THERE ANY OTHER PROBLEMS WITH RELYING ON ANALYSTS' GROWTH PROJECTIONS?

A. Yes. While the foregoing discussion shows two reasons why we cannot rely on analysts' growth rate projections to provide fair, qualitative indicators of utility growth in a stable growth DCF Model, the third reason is perhaps the most obvious and indisputable. Various institutional analysts, such as Zacks, Value Line, and Bloomberg, publish estimated projections of earnings growth for utilities. These estimates, however, are *short-term* growth rate projections, ranging from 3 – 10 years. Many utility ROE analysts, however, disingenuously insert these short-term growth projections into the DCF Model as *long-term* growth rate projections. For example, assume that an analyst at Bloomberg estimates that a utility's earnings will grow by 7% per year over the next 3 years. This analyst may have based this short-term forecast on a utility's plans to replace depreciated rate base (i.e., "flatworm" growth) or on an anticipated awarded return that is above market-based cost of equity (i.e., "circular reference" problem). When a utility witness uses this figure in a DCF Model, however, it is the *witness*, not the Bloomberg analyst that is testifying to the regulator that the utility's earnings will qualitatively grow by 7% per year over the *long-term*, which is an unrealistic assumption.

4. Long-Term Growth Rate Recommendation

Q. DESCRIBE THE GROWTH RATE INPUT USED IN YOUR DCF MODEL.

A. I considered various qualitative determinants of growth for ABACO, along with the maximum allowed growth rate under basic principles of finance and economics. The following chart shows the various long-term growth determinants discussed in this section.[49]

[49] Exhibit DJG-5.

Figure 8:
Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate
Nominal GDP	3.9%
Real GDP	1.9%
Inflation	2.0%
Risk Free Rate	1.6%
Highest	**3.9%**

For the long-term growth rate in my DCF model, I selected the maximum, reasonable long-term growth rate of 3.9%, which means my model assumes that the Company's qualitative growth in earnings will match the nominal growth rate of the entire U.S. economy over the long run – a very generous assumption.

Q. PLEASE DESCRIBE THE FINAL RESULTS OF YOUR DCF MODEL.

A. I used the Quarterly Approximation DCF Model discussed above to estimate the Company's cost of equity capital. I obtained an average of reported dividends and stock prices from the proxy group, and I used a reasonable terminal growth rate estimate for the Company. Applying this model, my DCF cost of equity estimate for the Company is 7.5%.[50]

[50] Exhibit DJG-6.

F. Response to Mr. Trogonoski's DCF Model

Q. MR. TROGONOSKI'S DCF MODEL YIELDED MUCH HIGHER RESULTS. DID YOU FIND ANY ERRORS IN HIS ANALYSIS?

A. Yes. Mr. Trogonoski's DCF Model produced a cost of equity result as high as 11.7%.[51] The results of Mr. Trogonoski's DCF Model are overstated primarily because of a fundamental error regarding his growth rate inputs.

Q. DESCRIBE THE PROBLEMS WITH MR. TROGONOSKI'S LONG-TERM GROWTH INPUT.

A. Mr. Trogonoski used long-term growth rates in his proxy group as high as 12.5%,[52] which is more than three times higher than the projected, long-term nominal U.S. GDP growth rate (approximately 4.0%). This means Mr. Trogonoski's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long-term, especially a regulated utility company with a defined service territory. Furthermore, Mr. Trogonoski used short-term, quantitative growth estimates published by analysts to estimate equivalent long-term rates. As discussed above, these analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for short-term growth. For example, Mr. Trogonoski incorporated a 12.5% growth rate for South Jersey Industries ("SJI"), which was reported by Yahoo! Finance.[53] This would mean that the analyst from Yahoo! Finance apparently

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[51] 38.5.146.1 DCF Analysis.

[52] *Id*.

[53] *Id*.

thinks SJI's earnings will quantitatively increase by 12.5% each year over the next *several* years. However, it is Mr. Trogonoski, not the commercial analyst, who is suggesting to the Commission that SJI's earnings will grow by more than two times the amount of U.S. GDP growth every year for many decades into the future.[54] This assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. The growth rate assumptions used by Mr. Trogonoski for many of the proxy companies incorporate the same misleading assumptions.[55] As discussed above, long-term growth rates in excess of GDP will eventually result in unrealistically high financial projections. For example, SJI's revenue in 2019 was $1.6 billion. If we applied Mr. Trogonoski's annual long-term growth rate of 12.5% to SJI's 2019 earnings, in just 30 years SJI's annual earnings would be in excess of $54 billion.

VII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. DESCRIBE THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[56] The CAPM estimates this expected return. The various assumptions, theories, and equations involved

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[54] *Id*. Technically, the constant growth rate in the DCF Model grows dividends each year to "infinity." Yet, even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

[55] *Id*.

[56] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

in the CAPM are discussed further in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. As discussed earlier, the U.S. Supreme Court has recognized that "the amount of *risk* in the business is a most important factor" in determining the allowed rate of return,[57] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding *risks*."[58] The CAPM is a useful model because it directly considers the amount of risk inherent in a business and directly measures the most important component of a fair rate of return analysis: Risk.

Q. DESCRIBE THE INPUTS FOR THE CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is discussed separately below.

A. <u>The Risk-Free Rate</u>

Q. EXPLAIN THE RISK-FREE RATE.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a given investment. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to

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[57] *Wilcox*, 212 U.S. at 48 (emphasis added).

[58] *Hope Natural Gas Co*., 320 U.S. at 603 (emphasis added).

represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. IS IT PREFERABLE TO USE THE YIELD ON LONG-TERM TREASURY BONDS FOR THE RISK-FREE RATE IN THE CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. As a result, short-term Treasury bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted in a risk-free rate of 1.65%.[59]

B. The Beta Coefficient

Q. HOW IS THE BETA COEFFICIENT USED IN THIS MODEL?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (less) than one is more (less) risky than the market portfolio. An index such as the

[59] Exhibit DJG-7.

S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. As discussed above, beta also represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%.

Q. DESCRIBE THE SOURCE FOR THE BETAS YOU USED IN YOUR CAPM ANALYSIS.

A. I used betas recently published by Value Line Investment Survey. The average beta for the proxy group is only 0.91.[60] Thus, we have an objective measure to prove the well-known concept that utility stocks are less risky than the average stock in the market.

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[60] Exhibit DJG-8.

C. The Equity Risk Premium

Q. DESCRIBE THE EQUITY RISK PREMIUM.

A. The final term of the CAPM is the equity risk premium ("ERP"), which is the required return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts agree that "the single most important variable for making investment decisions is the equity risk premium."[61] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. Historical Average

Q. DESCRIBE THE HISTORICAL EQUITY RISK PREMIUM.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

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[61] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 4 (Princeton University Press 2002).

Q. WHAT ARE THE LIMITATIONS OF RELYING SOLELY ON A HISTORICAL AVERAGE TO ESTIMATE THE CURRENT OR FORWARD-LOOKING ERP?

A. As I mentioned, many investors use the historic ERP because it is convenient and easy to calculate. What matters in the CAPM model, however, is not the actual risk premium from the past, but rather the current and forward-looking risk premium.[62] Some investors may think that a historic ERP provides some indication of what the prospective risk premium is; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually *lower* than the historical ERP. In what is considered a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[63] This is due in large part to what is known as "survivorship bias" or "success bias" — a tendency for failed companies to be excluded from historical indices.[64] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP:

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[62] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

[63] Elroy Dimson, Paul Marsh & Mike Staunton, Triumph of the Optimists: 101 Years of Global Investment Returns 194 (Princeton University Press 2002).

[64] *Id*. at 34.

> The result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent.[65]

Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[66]

Regardless of the variations in historic ERP estimates, many leading scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[67]

Q. DID YOU RELY ON THE HISTORICAL ERP AS PART OF YOUR CAPM ANALYSIS IN THIS CASE?

A. No. Due to the limitations of this approach, I primarily relied on the ERP reported in expert surveys and the implied ERP method discussed below.

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[65] *Id*. at 194.

[66] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition* 17 (New York University 2015).

[67] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

2. <u>EXPERT SURVEYS</u>

Q. DESCRIBE THE EXPERT SURVEY APPROACH TO ESTIMATING THE ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers and other executives around the country and asking them what they think the ERP is. Graham and Harvey have performed such a survey since 1996. In their 2018 survey, they found that experts around the country believe the current ERP is 4.4%.[68] The IESE Business School conducts a similar expert survey. Their 2020 expert survey reported an average ERP of 5.6%.[69]

3. <u>IMPLIED EQUITY RISK PREMIUM</u>

Q. DESCRIBE THE IMPLIED EQUITY RISK PREMIUM APPROACH.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Myron Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many years.[70] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept

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[68] John R. Graham and Campbell R. Harvey, *The Equity Risk Premium in 2018*, at 3 (Fuqua School of Business, Duke University 2014), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162.

[69] Pablo Fernandez, Pablo Linares & Isabel F. Acin, *Market Risk Premium used in 59 Countries in 2018: A Survey,* at 3 (IESE Business School 2018), copy available at http://www.valumonics.com/wp-content/uploads/2017/06/Discount-rate-Pablo-Fern%C3%A1ndez.pdf. IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

[70] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102-10 (Management Science Vol. 3, No. 1 Oct. 1956).

in both models is the same: The current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). The following formula shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: The implied market return.[71]

Equation 2:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

[71] *See* Exhibit DJG-9 for detailed calculation.

where: V_{500} = *current value of index (S&P 500)*
$CY_{1\text{-}5}$ = *average cash yield over last five years (includes dividends and buybacks)*
g = *compound growth rate in earnings over last five years*
R_F = *risk-free rate*
K = *implied market return (this is what we are solving for)*
TV = *terminal value* $= CY_5\,(1+R_F)\,/\,K$

The discount rate is called the "implied" return here because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP.

Equation 3:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. DISCUSS THE RESULTS OF YOUR IMPLIED ERP CALCULATION.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 7.6%.[72] I subtracted

[72] *Id*.

the risk-free rate to arrive at the implied equity risk premium of 5.9%.[73] Dr. Aswath Damodaran, arguably one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. Using variations of this method, he calculates and publishes his ERP results each month. Dr. Damodaran's *highest* ERP estimate for October 2020 using several implied ERP variations was 5.5%.[74]

Q. WHAT ARE THE RESULTS OF YOUR FINAL ERP ESTIMATE?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys, the implied ERP calculations discussed above, and the estimated ERP reported by Duff & Phelps.[75] The results are presented in the following figure:

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[73] *Id*.

[74] http://pages.stern.nyu.edu/~adamodar/

[75] *See also* Exhibit DJG-10.

Figure 9:
Equity Risk Premium Results

IESE Business School Survey	5.6%
Graham & Harvey Survey	4.4%
Duff & Phelps Report	6.0%
Damodaran (highest Dec. result)	5.5%
Damodaran (COVID Adjusted)	4.7%
Garrett	5.9%
Average	**5.4%**
Highest	**6.0%**

While it would be reasonable to select any one of these ERP estimates to use in the CAPM, I conservatively selected the *highest* ERP estimate of 6.0% to use in my CAPM analysis. All else held constant, a higher ERP used in the CAPM will result in a higher cost of equity estimate.

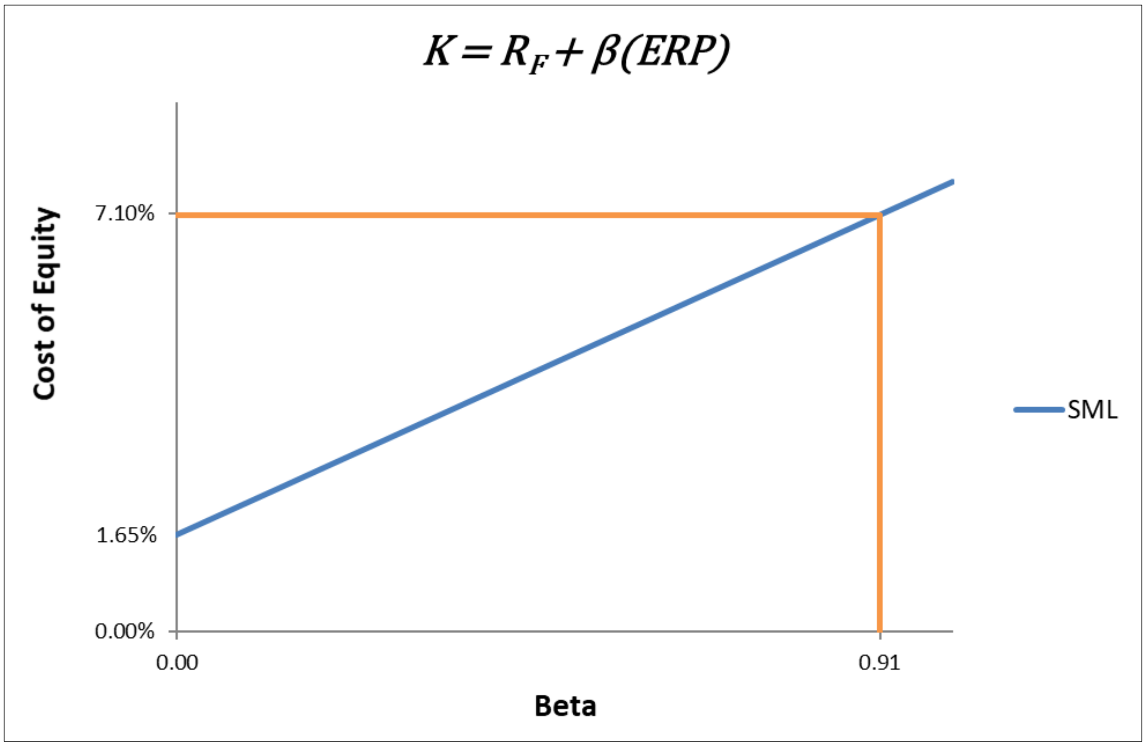
Q. PLEASE EXPLAIN THE FINAL RESULTS OF YOUR CAPM ANALYSIS.

A. Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, I estimate that the Company's CAPM cost of equity is 7.1%.[76] The CAPM can be displayed graphically through what is known as the Security Market Line ("SML"). The following figure shows the expected return (cost of equity) on the y-axis, and the average

[76] Exhibit DJG-11.

beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

Figure 10:
CAPM Graph



The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.91 for the proxy group, the estimated CAPM cost of equity for the Company is 7.1%.

D. Response to Mr. Trogonoski's CAPM Analysis

Q. MR. TROGONOSKI'S CAPM ANALYSIS YIELDS CONSIDERABLY HIGHER RESULTS. DID YOU FIND SPECIFIC PROBLEMS WITH MR. TROGONOSKI'S CAPM ASSUMPTIONS AND INPUTS?

A. Yes. The median result of Mr. Trogonoski's various CAPM evaluations is 13.1%,[77] which is considerably higher than my estimate. The main problem with Mr. Trogonoski's CAPM cost of equity result stems primarily from his estimate of the ERP. In addition, his input for the risk-free rate is overestimated.

Q. DID MR. TROGONOSKI RELY ON A REASONABLE MEASURE FOR THE ERP?

A. No, he did not. Mr. Trogonoski used an ERP estimate of 12.44% in his CAPM.[78] The ERP is one of three inputs in the CAPM equation, and it is one of the most important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The <u>highest</u> ERP found from my research and analysis is only 6.0%.[79] This means that Mr. Trogonoski's ERP estimate is more than twice as high as the highest reasonable ERP I could either find or calculate. And, as noted, it is also considerably higher than that of reputable analysts.

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[77] Exhibit DWD-4.

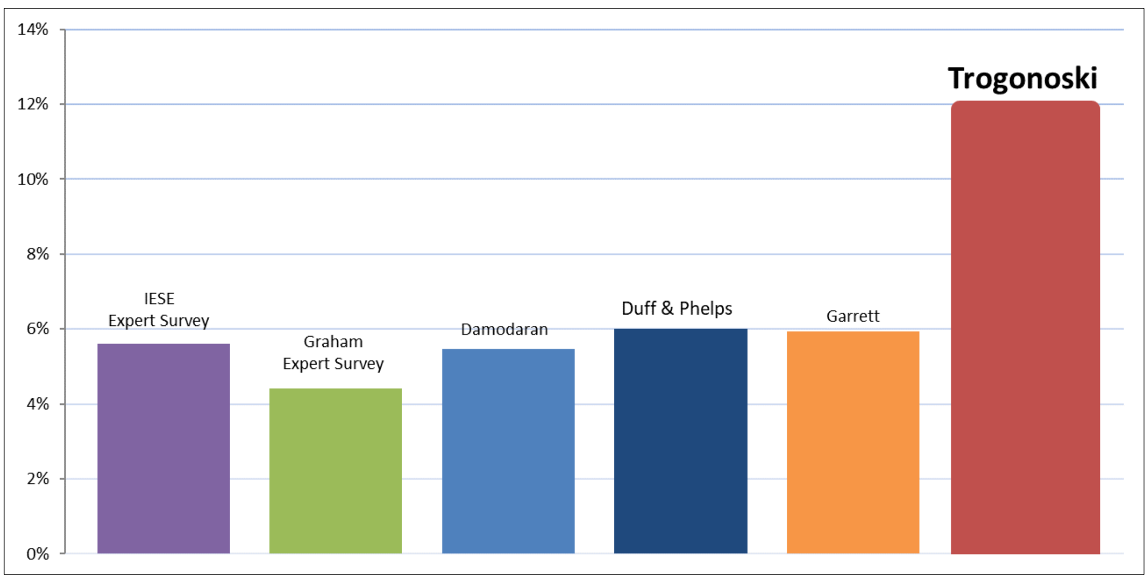
[78] *Id*.

[79] Exhibit DJG-10.

Q. PLEASE DISCUSS AND ILLUSTRATE HOW MR. TROGONOSKI'S ERP COMPARES WITH OTHER ESTIMATES FOR THE ERP.

A. As discussed above, Graham and Harvey's 2018 expert survey reports an average ERP of 4.4%. The 2020 IESE Business School expert survey reports an average ERP of 5.6%. Similarly, Duff & Phelps recently estimated an ERP of 6.0%. The following chart illustrates that Mr. Trogonoski's ERP estimate is far out of line with industry norms.[80]

Figure 11:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP (as well as my estimate), which do not have a wide variance, Mr. Trogonoski's ERP estimate is clearly not within the range of reasonableness. As a result, his CAPM cost of equity estimate is overstated and unreliable.

[80] *See* Exhibit DJG-10. The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under varying assumptions.

VIII. OTHER COST OF EQUITY ISSUES

Q. DO YOU HAVE A RESPONSE TO OTHER COST OF EQUITY ISSUES RAISED BY MR. TROGONOSKI?

A. Yes. Mr. Trogonoski discusses additional firm-specific risk factors in his testimony as having an increasing effect on the cost of equity and awarded return for ABACO. In addition, Mr. Trogonoski suggests that ABACO's relatively small size should have an effect on its cost of equity.

1. Company-Specific Risk Factors

Q. DESCRIBE MR. TROGONOSKI'S TESTIMONY REGARDING BUSINESS RISKS.

A. In his Direct Testimony, Mr. Trogonoski suggests that various firm-specific risk factors should have an increasing effect on ABACO's cost of equity, including customer concentration and the potential for customer bypass.[81]

Q. DO YOU AGREE WITH MR. TROGONOSKI THAT THESE FIRM-SPECIFIC RISK FACTORS SHOULD INFLUENCE ABACO'S COST OF EQUITY OR AWARDED ROE?

A. No. All companies face business risks, including the other utilities in the proxy group; business risks are not unique to ABACO. In fact, I see similar arguments made by essentially every utility in every rate case. This observation actually reinforces the well-known concept in finance that firm-specific risks are unrewarded by the market. In other words, not every utility can receive a premium to their cost of equity estimate for their

[81] See Direct Testimony of Kurt G. Trogonoski, pp. 26-29.

supposed unique business risks. Moreover, firm-specific risk can be eliminated through portfolio diversification. Scholars widely recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing.[82]

Unlike interest rate risk, inflation risk, and other market risks that affect all companies in the stock market, the risk factors discussed by Mr. Trogonoski are merely business risks specific to ABACO. Investors do not require an additional return for these firm-specific business risks. Another way to consider this issue is to look at the CAPM and DCF Model. Did the creators of these highly regarded cost of equity models, which have been relied upon for decades by companies and investors to make crucial business decisions, simply neglect to add an input for business risks? The DCF Model considers stock price, dividends, and a long-term growth rate. The CAPM considers the risk-free rate, beta, and the equity risk premium. Neither model includes an input for business risks due to the well-known truth that investors do not expect a return for such risks. Therefore, the Company's firm-specific business risks, while perhaps relevant to other issues in the rate case, have no meaningful effect on the cost of equity estimate. Rather, it is market risk that is rewarded by the market, and this concept is thoroughly addressed in my CAPM analysis discussed above.

[82] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

2. <u>Small Size Premium</u>

Q. PLEASE DESCRIBE MR. TROGONOSKI'S POSITION REGARDING THE SIZE PREMIUM.

A. Mr. Trogonoski suggests that ABACO's size should somehow have an increasing effect on its cost of equity estimate.[83] Mr. Trogonoski recommends a small size adjustment of "at least 391 basis points" for the small size premium.[84]

Q. DO YOU AGREE WITH MR. TROGONOSKI REGARDING THE SIZE PREMIUM OR SIZE EFFECT?

A. No, I do not. To the extent Mr. Trogonoski is adjusting his CAPM result upward to account for the "size effect" phenomenon, I disagree with his position because numerous studies have shown that small cap stocks do not consistently outperform large-cap stocks. The "size effect" phenomenon arose from a 1981 study conducted by Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[85] Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for approximately two years. . . ."[86] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In the more recent study,

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[83] *See* Direct Testimony of John P. Trogonoski, pp. 23-26.

[84] *Id*. at p. 26, lines 9-11.

[85] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

[86] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

Triumph of the Optimists, the authors conducted an extensive empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[87]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium;" yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[88]

In addition to the studies discussed above, other scholars have concluded similar results. According to Kalesnik and Beck:

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[87] *Id*. at 133.

[88] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[89]

Thus, the size-effect phenomenon has been essentially extinct for nearly 40 years, and it should have no application in this case.

Q. HAS THE COMMISSION PREVIOUSLY REJECTED THE SMALL SIZE PREMIUM ADJUSTMENT?

A. Yes. In the Final Order of Docket No. D2017.9.80, the Commission provided a thorough discussion of the small size premium. In rejecting the utilities' request for a size premium adjustment, the Commission found:

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[89] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx (emphasis added).

> Both large and small utilities are insulated from the type of risk which may present for smaller firms, because they are economically regulated by public service commissions. As noted above, the only empirical evidence of size-based risk suggests no correlation. Moreover, the Commission reasons that risk has more to do with the peculiarities of the service territory and business model of a regulated utility than its size. Large utilities may serve a more sprawling service territory that exposes them to greater risk of natural disasters, like wildfires, or may serve more dense urban communities where infrastructure may be more aged and dangerous, or where gas line replacements are more difficult to undertake. Indeed, the riskiest utilities may be those which have the largest balance sheets such that in the first instance they may make big bets that fail.[90]

The Commission continued by outlining specific evidence that should be shown by a utility seeking a size premium.

> In the future, should a utility applicant seek [a size premium], they must demonstrate through clear evidence several things. First, they must demonstrate that size serves as an adequate proxy for utility-specific, unsystematic risk. Second, show that the risk premia effect that appears for small public companies relative to larger public companies is actually translatable to the regulated utility sector; the primary evidence of this should be of proxy companies, or other direct evidence which suggests a size-based return differential associated with regulated utilities. Third, and relatedly, such an applicant must clearly answer through comprehensive analysis the problem identified in Order 7433f. Such analysis would include breaking down a public holding company into its various operating companies, and contrasting their performance and returns, which presumably would be reporting in the holding companies' financials, with market-wide risk premia.

In this case, ABACO has not me the specific burden of proof outlined by the Commission to establish a size premium. Further, it is noteworthy that the smallest company in the proxy group based on market capitalization, Northwest Natural Gas Company, has the smallest beta in the proxy group (0.8). Thus, the smallest company in the proxy group has

[90] Final Order No. 7575c, Cause No. D2017.9.80, ¶145 (9-26-2018).

relatively little market risk.[91] Finally, I would also note a size premium of 3.91% is significantly greater than any size premium I can recall being requested in a rate proceeding.

IX. COST OF EQUITY SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF THE CAPM AND DCF MODEL DISCUSSED ABOVE.

A. The following table shows the cost of equity results from each model I employed in this case.[92]

**Figure 12:
Cost of Equity Summary**

Model	Cost of Equity
Discounted Cash Flow Model	7.5%
Capital Asset Pricing Model	7.1%
Average	**7.3%**

The cost of equity indicated by the results of the DCF Model and the CAPM is approximately 7.3%.

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[91] *See* Exhibit DJG-2 regarding market capitalization figures; *see also* Exhibit DJG-8 (two other companies in the group also have betas of 0.8).

[92] *See* Exhibit DJG-12.

Q. IS THERE A MARKET INDICATOR THAT YOU CAN USE TO TEST THE REASONABLENESS OF YOUR COST OF EQUITY ESTIMATE?

A. Yes, there is. The CAPM is a risk premium model based on the fact that all investors will require, at a minimum, a return equal to the risk-free rate when investing in equity securities. Of course, the investors will also require a premium on top of the risk-free rate to compensate them for the risk they have assumed. If an investor bought every stock in the market portfolio, he would require the risk-free rate, plus the ERP discussed above. Recall that the risk-free rate plus the ERP is called the required return on the market portfolio. This could also be called the market cost of equity. It is undisputed that the cost of equity of utility stocks must be less than the total market cost of equity. This is because utility stocks are less risky than the average stock in the market. (We proved this above by showing that utility betas are less than one). Therefore, once we determine the market cost of equity, it gives us a "ceiling" below which ABACO's actual cost of equity must lie.

Q. DESCRIBE HOW YOU ESTIMATED THE MARKET COST OF EQUITY.

A. The methods used to estimate the market cost of equity are necessarily related to the methods used to estimate the ERP discussed above. In fact, the ERP is calculated by taking the market cost of equity less the risk-free rate. Therefore, in estimating the market cost of equity, I relied on the same methods discussed above to estimate the ERP: (1) consulting expert surveys; and (2) calculating the implied ERP. The results of my market cost of equity analysis are presented in the following table:[93]

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[93] *See* Exhibit DJG-13.

Figure 13:
Market Cost of Equity Summary

Source	Estimate
IESE Survey	7.2%
Graham Harvey Survey	6.1%
Damodaran	7.1%
Garrett	7.6%
Average	7.0%
Highest	7.6%

As shown in this table, the highest market cost of equity from these sources is only 7.6%. Therefore, it is not surprising that the CAPM and DCF Model indicate a cost of equity for the Company of only 7.3%. In other words, any cost of equity estimates for the Company (or any regulated utility) that is *above* the market cost of equity should be viewed as an overestimate.

X. CAPITAL STRUCTURE

Q. DESCRIBE THE COMPANY'S PROPOSED CAPITAL STRUCTURE.

A. Mr. Trogonoski proposes a capital structure consisting of 91.46% equity and 8.54% debt.[94]

[94] Direct Testimony of John P. Trogonoski, p. 29, lines 5-10.

Q. DO YOU AGREE WITH ABACO'S PROPOSED CAPITAL STRUCTURE?

A. No. For the reasons discussed below, I recommend the Commission reject ABACO's proposed capital structure, and instead adopt a capital structure consisting of 49% debt and 51% equity.

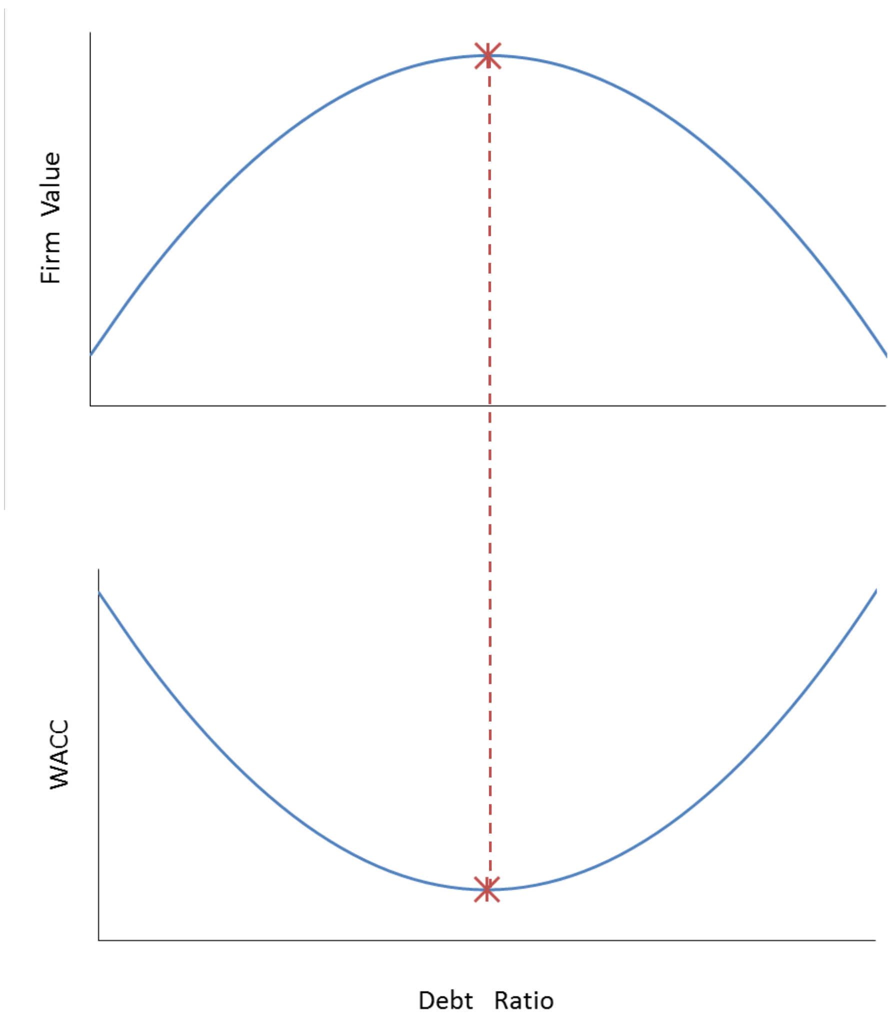
Q. DESCRIBE IN GENERAL THE CONCEPT OF A COMPANY'S "CAPITAL STRUCTURE."

A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issues that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their weighted average cost of capital ("WACC") by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. IS IT TRUE THAT, BY INCREASING DEBT, COMPETITIVE FIRMS CAN ADD VALUE AND REDUCE THEIR WACC?

A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the likelihood of loss increases. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. Thus, if debt financing is too high, the firm's WACC will increase instead of decrease. The following figure illustrates these concepts.

Figure 14:
Optimal Debt Ratio



As shown in this figure, a competitive firm's value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the additional risks to both bondholders and shareholders, as each type of investor will demand higher returns for the additional risk they have assumed.[95]

Q. DOES THE RATE BASE RATE OF RETURN MODEL EFFECTIVELY INCENTIVIZE UTILITIES TO OPERATE AT THE OPTIMAL CAPITAL STRUCTURE?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 4:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

where:	RR	=	*revenue requirement*
	O	=	*operating expenses*
	d	=	*depreciation expense*
	T	=	*corporate tax*
	$\boldsymbol{r}$	=	***weighted average cost of capital (WACC)***
	A	=	*plant investments*
	D	=	*accumulated depreciation*

[95] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 440-41 (3rd ed., South Western Cengage Learning 2010).

As shown in this equation, utilities can increase their revenue requirement by <u>increasing</u> their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

Q. CAN UTILITIES GENERALLY AFFORD TO HAVE HIGHER DEBT LEVELS THAN OTHER INDUSTRIES?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. <u>Utilities</u>, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[96]

Note that the author explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively higher levels of debt to achieve their optimal capital structure. There are objective methods available to estimate the optimal capital structure, as discussed further below.

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[96] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 196 (3rd ed., John Wiley & Sons, Inc. 2012) (emphasis added).

Q. IS IT APPROPRIATE TO USE THE PROXY GROUP FOR KEY INPUTS TO THE CAPM AND DCF MODELS WHILE COMPLETELY IGNORING CAPITAL STRUCTURE?

A. No, I do not believe it is. Utilities are not naturally incentivized to operate with optimal (i.e., high enough) levels of debt in their capital structures. Thus, simply relying on the average debt ratio of the proxy group may indicate a lower-than-optimal debt ratio. However, it can nonetheless be instructive to consider the debt ratios of the proxy group as a gauge for the proper debt ratio of the utility being studied. Moreover, it is not advisable to use key inputs from the proxy group into the cost of equity models (such as betas, growth rates, stock prices, etc.), while proposing a capital structure that is significantly different than the proxy group. This is because these metrics are necessarily related to each other. For example, if a company had an extremely high debt ratio, it would likely have an increasing effect on its betas over time (all else held constant), due to the increasing effect that the debt ratio has on its overall risk profile.

Q. WHAT IS THE AVERAGE DEBT RATIO OF THE PROXY GROUP?

A. The average debt ratio of the proxy group in this case is 49%.[97] In contrast, Mr. Trogonoski is proposing a debt ratio of only 8.54%.

[97] *See* Exhibit DJG-16.

Q. FOR REFERENCE, PROVIDE A COMPARISON OF THE PROXY GROUP'S DEBT RATIO WITH THOSE FROM OTHER INDUSTRIES.

A: For reference, there are thousands of companies in U.S. industries with higher debt ratios than that of the proxy group. Moreover, these firms have an average debt ratio of greater than 60%.[98] The following figure shows a sample of these industries with debt ratios higher than 55%.[99]

[98] *See* Exhibit DJG-16.

[99] *See* Exhibit DJG-15.

Figure 15:
Industries with Debt Ratios Greater than 55%

Industry	# Firms	Debt Ratio
Tobacco	17	96%
Financial Svcs.	232	95%
Retail (Building Supply)	17	90%
Hospitals/Healthcare Facilities	36	88%
Advertising	47	80%
Retail (Automotive)	26	79%
Brokerage & Investment Banking	39	77%
Auto & Truck	13	75%
Food Wholesalers	17	70%
Bank (Money Center)	7	69%
Transportation	18	67%
Hotel/Gaming	65	67%
Packaging & Container	24	66%
Retail (Grocery and Food)	13	66%
Broadcasting	27	65%
R.E.I.T.	234	64%
Retail (Special Lines)	89	64%
Green & Renewable Energy	22	**64%**
Recreation	63	63%
Software (Internet)	30	63%
Air Transport	18	**63%**
Retail (Distributors)	80	62%
Computers/Peripherals	48	61%
Telecom (Wireless)	18	**61%**
Farming/Agriculture	31	61%
Cable TV	14	**60%**
Computer Services	106	60%
Beverage (Soft)	34	60%
Telecom. Services	67	**60%**
Trucking	33	59%
Power	52	**59%**
Office Equipment & Services	22	58%
Chemical (Diversified)	6	58%
Retail (Online)	70	58%
Aerospace/Defense	77	58%
Oil/Gas Distribution	24	58%
Business & Consumer Services	165	57%
Construction Supplies	44	57%
Real Estate (Operations & Services)	57	56%
Household Products	127	56%
Environmental & Waste Services	82	56%
Rubber& Tires	4	56%
Total / Average	**2,215**	**66%**

Many of the industries shown here are, like public utilities, generally well-established industries with large amounts of capital assets. The shareholders of these industries demand higher debt ratios to maximize their profits. There are several notable industries that are relatively comparable to public utilities (highlighted in the figure above). For example, Green and Renewable Energy has an average debt ratio of 64% and Telecom Services has an average debt ratio of 60%. These debt ratios are significantly higher than the average debt ratio of the proxy group.

Q. WHAT IS YOUR RECOMMENDATION REGARDING ABACO'S CAPITAL STRUCTURE?

A. I recommend the Commission impute a capital structure consistent with the proxy group in this case, which consists of 49% debt and 51% equity (Mr. Trogonoski and I used the same proxy group).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. I reserve the right to supplement this testimony as needed with any additional information that has been requested from the Company but not yet provided. To the extent I have not addressed an issue, method, calculation, account, or other matter relevant to the Company's proposals in this proceeding, it should not be construed that I agree with the same.

APPENDIX A:

DISCOUNTED CASH FLOW MODEL THEORY

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. In its most general form, the DCF Model is expressed as follows:[100]

Equation 5:
General Discounted Cash Flow Model

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where:	P_0	=	*current stock price*
	$D_1 \ldots D_n$	=	*expected future dividends*
	k	=	*discount rate / required return*

The General DCF Model would require an estimation of an infinite stream of dividends. Since this would be impractical, analysts use more feasible variations of the General DCF Model, which are discussed further below.

The DCF Models rely on the following four assumptions:

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;

2. Investors discount the expected cash flows at the same rate (K) in every future period;

[100] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

3. The K obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and

4. Dividends, rather than earnings, constitute the source of value.

The General DCF can be rearranged to make it more practical for estimating the cost of equity. Regulators typically rely on some variation of the Constant Growth DCF Model, which is expressed as follows:

Equation 6:
Constant Growth Discounted Cash Flow Model

$$K = \frac{D_1}{P_0} + g$$

where:	K	=	*discount rate / required return on equity*
	D_1	=	*expected dividend per share one year from now*
	P_0	=	*current stock price*
	g	=	*expected growth rate of future dividends*

Unlike the General DCF Model, the Constant Growth DCF Model solves directly for the required return (K). In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be essentially substituted with a term representing the expected constant growth rate of future dividends (g). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (g). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

In addition to the four assumptions listed above, the Constant Growth DCF Model relies on four additional assumptions as follows:[101]

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[101] *Id.* at 254-56.

1. The discount rate (K) must exceed the growth rate (g);
2. The dividend growth rate (g) is constant in every year to infinity;
3. Investors require the same return (K) in every year; and
4. There is no external financing; that is, growth is provided only by the retention of earnings.

Since the growth rate in this model is assumed to be constant, it is important not to use growth rates that are unreasonably high. In fact, the constant growth rate estimate for a regulated utility with a defined service territory should not exceed the growth rate for the economy in which it operates.

The basic form of the Constant Growth DCF Model described above is sometimes referred to as the "Annual" DCF Model. This is because the model assumes an annual dividend payment to be paid at the end of every year, as well as an increase in dividends once each year. In reality however, most utilities pay dividends on a quarterly basis. The Constant Growth DCF equation may be modified to reflect the assumption that investors receive successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF Model.[102]

Equation 7:
Quarterly Approximation Discounted Cash Flow Model

$$K = \left[\frac{d_0(1+g)^{1/4}}{P_0} + (1+g)^{1/4}\right]^4 - 1$$

where:	K	=	*discount rate / required return*
	d_0	=	*current quarterly dividend per share*
	P_0	=	*stock price*
	g	=	*expected growth rate of future dividends*

[102] *Id.* at 348.

The Quarterly Approximation DCF Model assumes that dividends are paid quarterly, and that each dividend is constant for four consecutive quarters. All else held constant, this model results in the *highest* cost of equity estimate for the utility in comparison to other DCF Models because it accounts for the quarterly compounding of dividends. There are several other variations of the Constant Growth (or Annual) DCF Model, including a Semi-Annual DCF Model which is used by the Federal Energy Regulatory Commission ("FERC"). These models, along with the Quarterly Approximation DCF Model, have been accepted in regulatory proceedings as useful tools for estimating the cost of equity.

APPENDIX B:

CAPITAL ASSET PRICING MODEL THEORY

The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors demand higher returns for incurring additional risk.[103] The CAPM estimates this required return. The CAPM relies on the following assumptions:

1. Investors are rational, risk-adverse, and strive to maximize profit and terminal wealth;
2. Investors make choices based on risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;
3. Investors have homogenous expectations of risk and return;
4. Investors have identical time horizons;
5. Information is freely and simultaneously available to investors.
6. There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;
7. There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and,
8. Total asset quality is fixed, and all assets are marketable and divisible.[104]

While some of these assumptions may appear to be restrictive, they do not outweigh the inherent value of the model. The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

The basic CAPM equation is expressed as follows:

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[103] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

[104] *Id.*

Equation 8:
Capital Asset Pricing Model

$$K = R_F + \beta_i(R_M - R_F)$$

where: K = *required return*
R_F = *risk-free rate*
β = *beta coefficient of asset i*
R_M = *required return on the overall market*

There are essentially three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β); and (3) the equity risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate.

Raw Beta Calculations and Adjustments

A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance, as expressed in the following formula:[105]

Equation 9:
Beta

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where: β_i = *beta of asset i*
σ_{im} = *covariance of asset i returns with market portfolio returns*
$\sigma^2{}_m$ = *variance of market portfolio*

Betas that are published by various research firms are typically calculated through a regression analysis that considers the movements in price of an individual stock and movements in the price of the overall market portfolio. The betas produced by this regression analysis are considered "raw" betas. There is empirical evidence that raw betas should be adjusted to account

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[105] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180-81 (3rd ed., South Western Cengage Learning 2010).

for beta's natural tendency to revert to an underlying mean.[106] Some analysts use an adjustment method proposed by Blume, which adjusts raw betas toward the market mean of one.[107] While the Blume adjustment method is popular due to its simplicity, it is arguably arbitrary, and some would say not useful at all. According to Dr. Damodaran: "While we agree with the notion that betas move toward 1.0 over time, the [Blume adjustment] strikes us as arbitrary and not particularly useful."[108] The Blume adjustment method is especially arbitrary when applied to industries with consistently low betas, such as the utility industry. For industries with consistently low betas, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average. Vasicek proposed such a method, which is preferable to the Blume adjustment method because it allows raw betas to be adjusted toward an industry average, and also accounts for the statistical accuracy of the raw beta calculation.[109] In other words, "[t]he Vasicek adjustment seeks to overcome one weakness of the Blume model by not applying the same adjustment to every security; rather, a security-specific adjustment is made depending on the statistical quality of the regression."[110] The Vasicek beta adjustment equation is expressed as follows:

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[106] *See* Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 84-92 (Financial Management Autumn 1990).

[107] See Marshall Blume, *On the Assessment of Risk*, Vol. 26, No. 1 The Journal of Finance 1 (1971).

[108] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 187 (3rd ed., John Wiley & Sons, Inc. 2012).

[109] Oldrich A. Vasicek, *A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas* 1233-1239 (Journal of Finance, Vol. 28, No. 5, December 1973).

[110] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 77-78 (Morningstar 2012).

Equation 10:
Vasicek Beta Adjustment

$$\beta_{i1} = \frac{\sigma^2_{\beta_{i0}}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_0 + \frac{\sigma^2_{\beta 0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_{i0}$$

where:	β_{i1}	=	*Vasicek adjusted beta for security i*
	β_{i0}	=	*historical beta for security i*
	β_0	=	*beta of industry or proxy group*
	$\sigma^2_{\beta 0}$	=	*variance of betas in the industry or proxy group*
	$\sigma^2_{\beta i0}$	=	*square of standard error of the historical beta for security i*

The Vasicek beta adjustment is an improvement on the Blume model because the Vasicek model does not apply the same adjustment to every security. A higher standard error produced by the regression analysis indicates a lower statistical significance of the beta estimate. Thus, a beta with a high standard error should receive a greater adjustment than a beta with a low standard error. As stated in Ibbotson:

> While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have a higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. *This is most useful in looking at companies in industries that on average have high or low betas*.[111]

Thus, the Vasicek adjustment method is statistically more accurate, and is the preferred method to use when analyzing companies in an industry that has inherently low betas, such as the utility industry. The Vasicek method was also confirmed by Gombola, who conducted a study

[111] *Id*. at 78 (emphasis added).

specifically related to utility companies. Gombola concluded that "[t]he strong evidence of auto-regressive tendencies in *utility* betas lends support to the application of adjustment procedures such as the . . . adjustment procedure presented by Vasicek."[112] Gombola also concluded that adjusting raw betas toward the market mean of 1.0 is *too high*, and that "[i]nstead, they should be adjusted toward a value that is less than one."[113] In conducting the Vasicek adjustment on betas in previous cases, it reveals that utility betas are even lower than those published by Value Line.[114] Gombola's findings are particular important here, because his study was conducted specifically on utility companies. This evidence indicates that using Value Line's betas in a CAPM cost of equity estimate for a utility company may lead to overestimated results. Regardless, adjusting betas to a level that is *higher* than Value Line's betas is not reasonable, and it would produce CAPM cost of equity results that are too high.

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[112] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 92 (Financial Management Autumn 1990) (emphasis added).

[113] *Id*. at 91-92.

[114] *See e.g.* Responsive Testimony of David J. Garrett, filed March 21, 2016 in Cause No. PUD 201500273 before the Corporation Commission of Oklahoma (the Company's 2015 rate case), at pp. 56 – 59.

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EDUCATION

University of Oklahoma — Norman, OK
Master of Business Administration — 2014
Areas of Concentration: Finance, Energy

University of Oklahoma College of Law — Norman, OK
Juris Doctor — 2007
Member, American Indian Law Review

University of Oklahoma — Norman, OK
Bachelor of Business Administration — 2003
Major: Finance

PROFESSIONAL DESIGNATIONS

Society of Depreciation Professionals
Certified Depreciation Professional (CDP)

Society of Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst (CRRA)

The Mediation Institute
Certified Civil / Commercial & Employment Mediator

WORK EXPERIENCE

Resolve Utility Consulting PLLC — Oklahoma City, OK
Managing Member — 2016 – Present
Provide expert analysis and testimony specializing in depreciation and cost of capital issues for clients in utility regulatory proceedings.

Oklahoma Corporation Commission — Oklahoma City, OK
Public Utility Regulatory Analyst — 2012 – 2016
Assistant General Counsel — 2011 – 2012
Represented commission staff in utility regulatory proceedings and provided legal opinions to commissioners. Provided expert analysis and testimony in depreciation, cost of capital, incentive compensation, payroll and other issues.

Perebus Counsel, PLLC — Oklahoma City, OK
Managing Member — 2009 – 2011
Represented clients in the areas of family law, estate planning, debt negotiations, business organization, and utility regulation.

Moricoli & Schovanec, P.C. — Oklahoma City, OK
Associate Attorney — 2007 – 2009
Represented clients in the areas of contracts, oil and gas, business structures and estate administration.

TEACHING EXPERIENCE

University of Oklahoma — Norman, OK
Adjunct Instructor – "Conflict Resolution" — 2014 – Present
Adjunct Instructor – "Ethics in Leadership"

Rose State College — Midwest City, OK
Adjunct Instructor – "Legal Research" — 2013 – 2015
Adjunct Instructor – "Oil & Gas Law"

PUBLICATIONS

American Indian Law Review — Norman, OK
"Vine of the Dead: Reviving Equal Protection Rites for Religious Drug Use" — 2006
(31 Am. Indian L. Rev. 143)

VOLUNTEER EXPERIENCE

Calm Waters — Oklahoma City, OK
Board Member — 2015 – 2018
Participate in management of operations, attend meetings, review performance, compensation, and financial records. Assist in fundraising events.

Group Facilitator & Fundraiser — 2014 – 2018
Facilitate group meetings designed to help children and families cope with divorce and tragic events. Assist in fundraising events.

St. Jude Children's Research Hospital — Oklahoma City, OK
Oklahoma Fundraising Committee — 2008 – 2010
Raised money for charity by organizing local fundraising events.

PROFESSIONAL ASSOCIATIONS

Oklahoma Bar Association — 2007 – Present

Society of Depreciation Professionals — 2014 – Present
Board Member – President — 2017
Participate in management of operations, attend meetings, review performance, organize presentation agenda.

Society of Utility Regulatory Financial Analysts — 2014 – Present

SELECTED CONTINUING PROFESSIONAL EDUCATION

Society of Depreciation Professionals — Austin, TX
"Life and Net Salvage Analysis" — 2015
Extensive instruction on utility depreciation, including actuarial and simulation life analysis modes, gross salvage, cost of removal, life cycle analysis, and technology forecasting.

Society of Depreciation Professionals — New Orleans, LA
"Introduction to Depreciation" and "Extended Training" — 2014
Extensive instruction on utility depreciation, including average lives and net salvage.

Society of Utility and Regulatory Financial Analysts — Indianapolis, IN
46th Financial Forum. "The Regulatory Compact: Is it Still Relevant?" — 2014
Forum discussions on current issues.

New Mexico State University, Center for Public Utilities — Santa Fe, NM
Current Issues 2012, "The Santa Fe Conference" — 2012
Forum discussions on various current issues in utility regulation.

Michigan State University, Institute of Public Utilities — Clearwater, FL
"39th Eastern NARUC Utility Rate School" — 2011
One-week, hands-on training emphasizing the fundamentals of the utility ratemaking process.

New Mexico State University, Center for Public Utilities — Albuquerque, NM
"The Basics: Practical Regulatory Training for the Changing Electric Industries" — 2010
One-week, hands-on training designed to provide a solid foundation in core areas of utility ratemaking.

The Mediation Institute — Oklahoma City, OK
"Civil / Commercial & Employment Mediation Training" — 2009
Extensive instruction and mock mediations designed to build foundations in conducting mediations in civil matters.

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Maryland Public Service Commission	Washington Gas Light Company	9651	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Florida Public Service Commission	Utilities, Inc. of Florida	20200139-WS	Cost of capital and authorized rate of return	Florida Office of Public Counsel
New Mexico Public Regulatory Commission	El Paso Electric Company	20-00104-UT	Cost of capital, depreciation rates, net salvage	City of Las Cruces and Doña Ana County
Public Utilities Commission of Nevada	Nevada Power Company	20-06003	Cost of capital, awarded rate of return, capital structure, earnings sharing	MGM Resorts International, Caesars Enterprise Services, LLC, Wynn Las Vegas, LLC, Smart Energy Alliance, and Circus Circus Las Vegas, LLC
Wyoming Public Service Commission	Rocky Mountain Power	20000-578-ER-20	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Florida Public Service Commission	Peoples Gas System	20200051-GU 20200166-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Wyoming Public Service Commission	Rocky Mountain Power	20000-539-EA-18	Depreciation rates, service lives, net salvage	Wyoming Industrial Energy Consumers
Public Service Commission of South Carolina	Dominion Energy South Carolina	2020-125-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	The City of Bethlehem	2020-3020256	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	GUD 10928	Depreciation rates, service lives, net salvage	Gulf Coast Service Area Steering Committee
Public Utilities Commission of the State of California	Southern California Edison	A.19-08-013	Depreciation rates, service lives, net salvage	The Utility Reform Network
Massachusetts Department of Public Utilities	NSTAR Gas Company	D.P.U. 19-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Georgia Public Service Commission	Liberty Utilities (Peach State Natural Gas)	42959	Depreciation rates, service lives, net salvage	Public Interest Advocacy Staff
Florida Public Service Commission	Florida Public Utilities Company	20190155-EI 20190156-EI 20190174-EI	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Illinois Commerce Commission	Commonwealth Edison Company	20-0393	Depreciation rates, service lives, net salvage	The Office of the Illinois Attorney General
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 49831	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Public Service Commission of South Carolina	Blue Granite Water Company	2019-290-WS	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Railroad Commission of Texas	CenterPoint Energy Resources	GUD 10920	Depreciation rates and grouping procedure	Alliance of CenterPoint Municipalities
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater	A-2019-3009052	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	19-00170-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Indiana Utility Regulatory Commission	Duke Energy Indiana	45253	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Maryland Public Service Commission	Columbia Gas of Maryland	9609	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-190334	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45235	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	18-12-009	Depreciation rates, service lives, net salvage	The Utility Reform Network
Oklahoma Corporation Commission	The Empire District Electric Company	PUD 201800133	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Arkansas Public Service Commission	Southwestern Electric Power Company	19-008-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 49421	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company	D.P.U. 18-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201800140	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2018.9.60	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45159	Depreciation rates, grouping procedure, demolition costs	Indiana Office of Utility Consumer Counselor
Public Service Commission of the State of Montana	NorthWestern Energy	D2018.2.12	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 201800097	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Wal-Mart
Nevada Public Utilities Commission	Southwest Gas Corporation	18-05031	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 48401	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201700496	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Maryland Public Service Commission	Washington Gas Light Company	9481	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Citizens Energy Group	45039	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 48371	Depreciation rates, decommissioning costs	Texas Municipal Group
Washington Utilities & Transportation Commission	Avista Corporation	UE-180167	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
New Mexico Public Regulation Commission	Southwestern Public Service Company	17-00255-UT	Cost of capital and authorized rate of return	HollyFrontier Navajo Refining; Occidental Permian

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 47527	Depreciation rates, plant service lives	Alliance of Xcel Municipalities
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2017.9.79	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Florida Public Service Commission	Florida City Gas	20170179-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-170485	Cost of capital and authorized rate of return	Washington Office of Attorney General
Wyoming Public Service Commission	Powder River Energy Corporation	10014-182-CA-17	Credit analysis, cost of capital	Private customer
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201700151	Depreciation, terminal salvage, risk analysis	Oklahoma Industrial Energy Consumers
Public Utility Commission of Texas	Oncor Electric Delivery Company	PUC 46957	Depreciation rates, simulated analysis	Alliance of Oncor Cities
Nevada Public Utilities Commission	Nevada Power Company	17-06004	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	El Paso Electric Company	PUC 46831	Depreciation rates, interim retirements	City of El Paso
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-24	Accelerated depreciation of North Valmy plant	Micron Technology, Inc.
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-23	Depreciation rates, service lives, net salvage	Micron Technology, Inc.
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 46449	Depreciation rates, decommissioning costs	Cities Advocating Reasonable Deregulation
Massachusetts Department of Public Utilities	Eversource Energy	D.P.U. 17-05	Cost of capital, capital structure, and rate of return	Sunrun Inc.; Energy Freedom Coalition of America
Railroad Commission of Texas	Atmos Pipeline - Texas	GUD 10580	Depreciation rates, grouping procedure	City of Dallas

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Utility Commission of Texas	Sharyland Utility Company	PUC 45414	Depreciation rates, simulated analysis	City of Mission
Oklahoma Corporation Commission	Empire District Electric Company	PUD 201600468	Cost of capital, depreciation rates	Oklahoma Industrial Energy Consumers
Railroad Commission of Texas	CenterPoint Energy Texas Gas	GUD 10567	Depreciation rates, simulated plant analysis	Texas Coast Utilities Coalition
Arkansas Public Service Commission	Oklahoma Gas & Electric Company	160-159-GU	Cost of capital, depreciation rates, terminal salvage	Arkansas River Valley Energy Consumers; Wal-Mart
Florida Public Service Commission	Peoples Gas	160-159-GU	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-16-0036	Cost of capital, depreciation rates, terminal salvage	Energy Freedom Coalition of America
Nevada Public Utilities Commission	Sierra Pacific Power Company	16-06008	Depreciation rates, net salvage, theoretical reserve	Northern Nevada Utility Customers
Oklahoma Corporation Commission	Oklahoma Gas & Electric Co.	PUD 201500273	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201500208	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 201500213	Cost of capital, depreciation rates, net salvage	Public Utility Division

Proxy Group Summary

Company	Ticker	[1] Market Cap. ($ millions)	[2] Market Category	[3] Value Line Safety Rank	[4] Financial Strength
Atmos Energy Corporation	ATO	12,500	Large Cap	1	A+
New Jersey Resources Corp.	NJR	3,600	Mid Cap	2	A+
Northwest Natural Gas Company	NWN	1,500	Small Cap	1	A
ONE Gas, Inc.	OGS	4,100	Mid Cap	2	A
South Jersey Inds.	SJI	2,300	Mid Cap	3	B++
Southwest Gas Holdings, Inc.	SWX	4,000	Mid Cap	3	A
Spire Inc.	SR	3,300	Mid Cap	2	B++
UGI Corporation	UGI	7,700	Mid Cap	2	B++

[1], [2], [4] Value Line Investment Survey

[2] Large Cap > $10 billion; Mid Cap > $2 billion; Small Cap > $200 million

DCF Stock and Index Prices

Ticker	^GSPC	ATO	NJR	NWN	OGS	SJI	SWX	SR	UGI
30-day Average	3641	97.66	34.73	48.92	78.57	22.80	66.02	64.01	35.72
Standard Deviation	54.5	2.50	1.52	1.58	2.02	0.72	3.47	1.55	0.78
11/10/20	3546	101.81	35.92	51.45	77.01	23.19	74.13	64.23	36.80
11/11/20	3573	100.11	35.69	50.32	76.96	22.95	72.15	62.95	36.27
11/12/20	3537	98.10	34.67	47.82	74.23	22.47	69.09	60.15	35.15
11/13/20	3585	101.52	36.09	49.15	76.44	23.11	70.37	62.65	36.09
11/16/20	3627	100.64	37.06	49.69	77.68	22.95	70.44	63.13	36.45
11/17/20	3610	99.42	36.66	49.51	78.09	22.98	69.82	63.90	35.92
11/18/20	3568	95.57	35.28	48.32	75.78	22.21	67.60	62.75	35.12
11/19/20	3582	94.50	35.46	47.85	76.29	22.36	67.42	62.76	35.70
11/20/20	3558	95.07	35.41	48.12	76.74	22.39	67.27	62.85	35.55
11/23/20	3578	96.25	35.93	49.11	78.12	23.05	67.39	63.69	36.20
11/24/20	3635	99.65	37.76	50.80	81.87	24.64	69.03	66.69	37.70
11/25/20	3630	98.79	37.11	50.75	82.13	24.33	68.04	65.74	37.29
11/27/20	3638	96.82	36.16	49.54	79.79	23.48	66.59	65.04	36.81
11/30/20	3622	95.89	32.71	47.92	79.18	22.71	64.25	63.32	35.15
12/01/20	3662	96.64	32.91	48.31	78.98	22.62	65.28	63.04	35.79
12/02/20	3669	96.19	33.24	48.51	79.12	22.71	66.12	63.42	35.78
12/03/20	3667	96.52	32.70	47.79	78.10	22.51	64.58	63.64	35.32
12/04/20	3699	97.27	33.39	48.65	79.66	22.74	65.13	64.32	35.70
12/07/20	3692	97.25	33.01	47.86	79.38	22.46	65.25	63.86	35.15
12/08/20	3702	97.59	33.21	47.69	78.90	22.43	64.66	63.65	35.18
12/09/20	3673	97.75	32.93	47.81	79.42	22.47	64.25	64.75	34.93
12/10/20	3668	98.17	32.76	47.56	79.77	22.38	62.87	64.89	35.12
12/11/20	3663	99.07	33.23	48.83	80.03	22.96	63.05	65.30	35.04
12/14/20	3647	99.51	34.10	50.19	80.01	23.37	63.97	65.59	34.98
12/15/20	3695	101.68	35.24	51.71	81.98	23.69	64.96	67.44	36.35
12/16/20	3701	99.35	34.92	50.48	80.08	23.28	63.58	65.85	35.70
12/17/20	3722	99.09	35.86	51.67	81.40	22.97	63.27	65.99	35.99
12/18/20	3709	95.11	34.65	49.19	78.25	22.29	61.15	64.23	35.54
12/21/20	3695	92.02	33.54	44.81	75.68	21.01	59.39	61.23	34.30
12/22/20	3687	92.33	34.37	46.19	75.92	21.30	59.39	63.11	34.50

All prices are adjusted closing prices reported by Yahoo! Finance, http://finance.yahoo.com

DCF Dividend Yields

		[1]	[2]	[3]
Company	Ticker	Dividend	Stock Price	Dividend Yield
Atmos Energy Corporation	ATO	0.625	97.66	0.64%
New Jersey Resources Corp.	NJR	0.333	34.73	0.96%
Northwest Natural Gas Company	NWN	0.480	48.92	0.98%
ONE Gas, Inc.	OGS	0.540	78.57	0.69%
South Jersey Inds.	SJI	0.303	22.80	1.33%
Southwest Gas Holdings, Inc.	SWX	0.570	66.02	0.86%
Spire Inc.	SR	0.650	64.01	1.02%
UGI Corporation	UGI	0.330	35.72	0.92%
Average		**$0.48**	**$56.05**	**0.92%**

[1] 2020 Q3 reported quarterly dividends per share. Nasdaq.com

[2] Average stock price from Exhibit DJG-3

[3] = [1] / [2] (quarterly dividend yield)

DCF Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate	
Nominal GDP	3.9%	[1]
Real GDP	1.9%	[2]
Inflation	2.0%	[3]
Risk Free Rate	1.6%	[4]
Highest	**3.9%**	

[1], [2], [3] CBO, The 2019 Long-Term Budget Outlook, p. 54, June 2019

[4] From Exhibit DJG-7

DCF Final Results

[1]	[2]	[3]	[4]
Dividend (d_0)	Stock Price (P_0)	Growth Rate (g)	**DCF Result**
$0.48	$56.05	3.90%	**7.5%**

[1] Average proxy dividend from Exhibit DJG-4

[2] Average proxy stock price from Exhibit DJG-3

[3] Highest growth determinant from Exhibit DJG-5

[4] Quarterly DCF Approximation = $[d_0(1 + g)^{0.25}/P_0 + (1 + g)^{0.25}]^4 - 1$

CAPM Risk-Free Rate

Exhibit DJG-7

Date	Rate
11/09/20	1.73%
11/10/20	1.75%
11/12/20	1.64%
11/13/20	1.65%
11/16/20	1.66%
11/17/20	1.62%
11/18/20	1.62%
11/19/20	1.58%
11/20/20	1.53%
11/23/20	1.56%
11/24/20	1.60%
11/25/20	1.62%
11/27/20	1.57%
11/30/20	1.58%
12/01/20	1.66%
12/02/20	1.70%
12/03/20	1.67%
12/04/20	1.73%
12/07/20	1.69%
12/08/20	1.67%
12/09/20	1.69%
12/10/20	1.65%
12/11/20	1.63%
12/14/20	1.63%
12/15/20	1.65%
12/16/20	1.66%
12/17/20	1.68%
12/18/20	1.70%
12/21/20	1.68%
12/22/20	1.65%
Average	**1.65%**

*Daily Treasury Yield Curve Rates on 30-year T-bonds, http://www.treasury.gov/resources-center/data-chart-center/interest-rates/

CAPM Beta Coefficient

Company	Ticker	Beta
Atmos Energy Corporation	ATO	0.80
New Jersey Resources Corp.	NJR	0.95
Northwest Natural Gas Company	NWN	0.80
ONE Gas, Inc.	OGS	0.80
South Jersey Inds.	SJI	1.05
Southwest Gas Holdings, Inc.	SWX	0.95
Spire Inc.	SR	0.85
UGI Corporation	UGI	1.05
Average		0.91

Betas from Value Line Investment Survey

CAPM Implied Equity Risk Premium Estimate

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2014	18,245	1,004	350	553	5.50%	1.92%	3.03%	4.95%
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%

Cash Yield	4.96%	[9]
Growth Rate	5.37%	[10]
Risk-free Rate	1.65%	[11]
Current Index Value	3,641	[12]

	[13]	[14]	[15]	[16]	[17]
Year	1	2	3	4	5
Expected Dividends	190	201	212	223	235
Expected Terminal Value					4023
Present Value	177	173	170	166	2954
Intrinsic Index Value	3641	[18]			
Required Return on Market	7.6%	[19]			
Implied Equity Risk Premium	**5.9%**	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500, Q4 2018
[1] Market value of S&P 500
[5] = [2] / [1]
[6] = [3] / [1]
[7] = [4] / [1]
[8] = [6] + [7]
[9] = Average of [8]
[10] = Compound annual growth rate of [2] = (end value / beginning value)^ $^{1/4}$-1
[11] Risk-free rate from DJG-1-7
[12] 30-day average of closing index prices from DJG-1-3 (^GSPC column)
[13-16] Expected dividends = [9]*[12]*(1+[10])^{n} ; Present value = expected dividend / (1+[11]+[19])^{n}
[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19])^{n}
[18] = Sum([13-17]) present values.
[19] = [20] + [11]
[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

CAPM Equity Risk Premium Results

IESE Business School Survey	5.6%	[1]
Graham & Harvey Survey	4.4%	[2]
Duff & Phelps Report	6.0%	[3]
Damodaran (highest Dec. result)	5.5%	[4]
Damodaran (COVID Adjusted)	4.7%	[5]
Garrett	5.9%	[6]
Average	**5.4%**	
Highest	**6.0%**	

[1] IESE Business School Survey 2020

[2] Graham and Harvey Survey 2018

[3] Duff & Phelps, 3-5-2020

[4], [5] http://pages.stern.nyu.edu/~adamodar/ , 11-1-20

[6] From Exhibit DJG-9

CAPM Final Results

		[1]	[2]	[3]	[4]
Company	Ticker	Risk-Free Rate	Value Line Beta	Risk Premium	CAPM Results
Atmos Energy Corporation	ATO	1.65%	0.80	6.0%	6.4%
New Jersey Resources Corp.	NJR	1.65%	0.95	6.0%	7.3%
Northwest Natural Gas Company	NWN	1.65%	0.80	6.0%	6.4%
ONE Gas, Inc.	OGS	1.65%	0.80	6.0%	6.4%
South Jersey Inds.	SJI	1.65%	1.05	6.0%	7.9%
Southwest Gas Holdings, Inc.	SWX	1.65%	0.95	6.0%	7.3%
Spire Inc.	SR	1.65%	0.85	6.0%	6.7%
UGI Corporation	UGI	1.65%	1.05	6.0%	7.9%
Average			0.91		**7.1%**

[1] From DJG-1-7, risk-free rate exhibit
[2] From DJG-1-8, beta exhibit
[3] From DJG-1-10, equity risk premium exhibit
[6] = [1] + [2] * [3]

Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	7.5%
Capital Asset Pricing Model	7.1%
Average	**7.3%**

Market Cost of Equity

Source	Estimate	
IESE Survey	7.2%	[1]
Graham Harvey Survey	6.1%	[2]
Damodaran	7.1%	[3]
Garrett	7.6%	[4]
Average	7.0%	
Highest	7.6%	

[1], [2], [3] Average reported ERP + riskfree rate from DJG-7

[4] From Exhibit DJG-9, Implied ERP exhibit

Market Cost of Equity vs. Awarded Returns

	[1]		[2]		[3]		[4]	[5]	[6]	[7]
	Electric Utilities		Gas Utilities		Total Utilities		S&P 500	T-Bond	Risk	Market
Year	ROE	#	ROE	#	ROE	#	Returns	Rate	Premium	COE
1990	12.70%	38	12.68%	33	12.69%	71	-3.06%	8.07%	3.89%	11.96%
1991	12.54%	42	12.45%	31	12.50%	73	30.23%	6.70%	3.48%	10.18%
1992	12.09%	45	12.02%	28	12.06%	73	7.49%	6.68%	3.55%	10.23%
1993	11.46%	28	11.37%	40	11.41%	68	9.97%	5.79%	3.17%	8.96%
1994	11.21%	28	11.24%	24	11.22%	52	1.33%	7.82%	3.55%	11.37%
1995	11.58%	28	11.44%	13	11.54%	41	37.20%	5.57%	3.29%	8.86%
1996	11.40%	18	11.12%	17	11.26%	35	22.68%	6.41%	3.20%	9.61%
1997	11.33%	10	11.30%	12	11.31%	22	33.10%	5.74%	2.73%	8.47%
1998	11.77%	10	11.51%	10	11.64%	20	28.34%	4.65%	2.26%	6.91%
1999	10.72%	6	10.74%	6	10.73%	12	20.89%	6.44%	2.05%	8.49%
2000	11.58%	9	11.34%	13	11.44%	22	-9.03%	5.11%	2.87%	7.98%
2001	11.07%	15	10.96%	5	11.04%	20	-11.85%	5.05%	3.62%	8.67%
2002	11.21%	14	11.17%	19	11.19%	33	-21.97%	3.81%	4.10%	7.91%
2003	10.96%	20	10.99%	25	10.98%	45	28.36%	4.25%	3.69%	7.94%
2004	10.81%	21	10.63%	22	10.72%	43	10.74%	4.22%	3.65%	7.87%
2005	10.51%	24	10.41%	26	10.46%	50	4.83%	4.39%	4.08%	8.47%
2006	10.32%	26	10.40%	15	10.35%	41	15.61%	4.70%	4.16%	8.86%
2007	10.30%	38	10.22%	35	10.26%	73	5.48%	4.02%	4.37%	8.39%
2008	10.41%	37	10.39%	32	10.40%	69	-36.55%	2.21%	6.43%	8.64%
2009	10.52%	40	10.22%	30	10.39%	70	25.94%	3.84%	4.36%	8.20%
2010	10.37%	61	10.15%	39	10.28%	100	14.82%	3.29%	5.20%	8.49%
2011	10.29%	42	9.92%	16	10.19%	58	2.10%	1.88%	6.01%	7.89%
2012	10.17%	58	9.94%	35	10.08%	93	15.89%	1.76%	5.78%	7.54%
2013	10.03%	49	9.68%	21	9.93%	70	32.15%	3.04%	4.96%	8.00%
2014	9.91%	38	9.78%	26	9.86%	64	13.52%	2.17%	5.78%	7.95%
2015	9.85%	30	9.60%	16	9.76%	46	1.38%	2.27%	6.12%	8.39%
2016	9.77%	42	9.54%	26	9.68%	68	11.77%	2.45%	5.69%	8.14%
2017	9.74%	53	9.72%	24	9.73%	77	21.61%	2.41%	5.08%	7.49%
2018	9.64%	37	9.62%	26	9.63%	63	-4.23%	2.68%	5.96%	8.64%
2019	9.64%	67	9.77%		9.64%	67	31.22%	1.92%	5.20%	7.12%

[1], [2], [3] Average annual authorized ROE for electric and gas utilities, RRA Regulatory Focus: Major Rate Case Decisions

[3] = [1] + [2]

[4], [5], [6] Annual S&P 500 return, 10-year T-bond Rate, and equity risk premium published by NYU Stern School of Business

[7] = [5] + [6] ; Market cost of equity represents the required return for investing in all stocks in the market for a given year

Competitive Industry Debt Ratios

Exhibit DJG-15

Industry	# Firms	Debt Ratio
Tobacco	17	96%
Financial Svcs. (Non-bank & Insurance)	232	95%
Retail (Building Supply)	17	90%
Hospitals/Healthcare Facilities	36	88%
Advertising	47	80%
Retail (Automotive)	26	79%
Brokerage & Investment Banking	39	77%
Auto & Truck	13	75%
Food Wholesalers	17	70%
Bank (Money Center)	7	69%
Transportation	18	67%
Hotel/Gaming	65	67%
Packaging & Container	24	66%
Retail (Grocery and Food)	13	66%
Broadcasting	27	65%
R.E.I.T.	234	64%
Retail (Special Lines)	89	64%
Green & Renewable Energy	22	64%
Recreation	63	63%
Software (Internet)	30	63%
Air Transport	18	63%
Retail (Distributors)	80	62%
Computers/Peripherals	48	61%
Telecom (Wireless)	18	61%
Farming/Agriculture	31	61%
Cable TV	14	60%
Computer Services	106	60%
Beverage (Soft)	34	60%
Telecom. Services	67	60%
Trucking	33	59%
Power	52	59%
Office Equipment & Services	22	58%
Chemical (Diversified)	6	58%
Retail (Online)	70	58%
Aerospace/Defense	77	58%
Oil/Gas Distribution	24	58%
Business & Consumer Services	165	57%
Construction Supplies	44	57%
Real Estate (Operations & Services)	57	56%
Household Products	127	56%
Environmental & Waste Services	82	56%
Rubber& Tires	4	56%
Transportation (Railroads)	8	55%
Retail (General)	18	54%
Chemical (Basic)	43	54%
Utility (Water)	17	54%
Building Materials	42	54%
Apparel	51	52%
Real Estate (Development)	20	51%
Healthcare Support Services	128	50%
Drugs (Biotechnology)	503	49%
Electrical Equipment	113	49%
Food Processing	88	48%
Machinery	120	48%
Furn/Home Furnishings	35	48%
Beverage (Alcoholic)	21	48%
Drugs (Pharmaceutical)	267	48%
Auto Parts	46	47%
Total / Average	**3,735**	**62%**

http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/dbtfund.htm

Proxy Group Debt Ratios

Exhibit DJG-16

Company	Ticker	Debt Ratio
Atmos Energy Corporation	ATO	40%
New Jersey Resources Corp.	NJR	45%
Northwest Natural Gas Company	NWN	48%
ONE Gas, Inc.	OGS	42%
South Jersey Inds.	SJI	61%
Southwest Gas Holdings, Inc.	SWX	50%
Spire Inc.	SR	49%
UGI Corporation	UGI	58%
Average		49%

Debt ratios from Value Line Investment Survey - 2020 projected

Weighted Average Rate of Return Proposal

Exhibit DJG-17

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Debt	49.0%	5.77%	2.83%
Equity	51.0%	9.00%	4.59%
Total	100.0%		7.42%

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing direct testimony of Paul R. Schulz and David J. Garrett on behalf of the Montana Consumer Counsel has been served upon the following persons by email this 25th day of January 2021.

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Suzanne Snow

Suzanne Snow, Secretary