DIRECT TESTIMONY OF

RALPH SMITH, CPA

BEFORE THE

RHODE ISLAND PUBLIC UTILITIES COMMISSION

SUEZ WATER RHODE ISLAND INC.

RATE CASE

DOCKET NO. 4800

ON BEHALF OF

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

June 8, 2018

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I. INTRODUCTION

Q. What is your name, occupation, and business address?

A. My name is Ralph Smith. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe the firm Larkin & Associates, PLLC.

A. Larkin & Associates, PLLC ("Larkin"), is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. Mr. Smith, please summarize your educational background and recent work experience.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination on my first sitting in 1979, received my C.P.A. license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association. I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. After graduating from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 38 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. Yes. I previously testified before the Rhode Island Public Utilities Commission for the Providence Water rate case, Docket No. 4618.

Q. Have you previously submitted testimony before other state regulatory commissions?

A. Yes. I have previously submitted testimony before many other state regulatory commissions, including Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law. My prior testimonies have included evaluations of numerous utility rate case filings and revenue requirement determinations.

Q. Have you prepared an exhibit describing your qualifications and experience?

A. Yes. I have attached Exhibit No. RCS-1, which is a summary of my regulatory experience and qualifications.

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC, was retained by the Division of Public Utilities and Carriers ("the Division") to review the rate request of Suez Water Rhode Island Inc. ("Suez Water," "SWRI" or “Company”). Accordingly, I am appearing on behalf of the Division.

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting the Division's overall recommended revenue requirement for Suez Water in this case. I sponsor several adjustments to the Company's proposed revenue requirement. I also address the impacts on the Company of the Tax Cuts and Jobs Act ("TCJA" or "2017 Tax Act") which was signed into law by President Trump on December 22, 2017. Finally, I address the Company's proposal for a Distribution System Improvement Charge ("DSIC") and recommend additional customer safeguards related to the DSIC.

Q. Have you attached any other Exhibits or Schedules to your testimony?

A. Yes. I prepared Exhibit RCS-2 which presents the revenue requirement calculation for the rate year ending September 30, 2019, giving effect to all of the adjustments I am recommending in this testimony. Exhibit RCS-2 contains schedules showing the revenue requirement, rate base, adjusted net operating income, capital structure and cost rates, and also includes schedules for each adjustment I am recommending.

Q. How will your testimony be organized?

A. In Section II, I present the overall financial summary for the base rate change to be effective for the rate year ended September 30, 2019, showing the revenue requirement and revenue increase recommended by the Division.

In Section III, I discuss my proposed adjustments which impact the Company's revenue requirement. Exhibit RCS-2 attached to my testimony presents the Division's Accounting and Revenue Requirement Schedules.

I address the impacts of the TCJA on the Company in Section IV of my testimony.

Finally, in Section V of my testimony I address the Company's proposed DSIC and the additional features and safeguards being recommended to protect ratepayers related to the DSIC.

II. OVERALL FINANCIAL SUMMARY – BASE RATE CHANGE

Q. What revenue increase is the Company seeking?

A. The Company is requesting a general base revenue adjustment of $1,024,856 per year to support its claimed total cost of service of $5,838,744 Overall, the increase requested by the Company would be 21.29%.

Q. What revenue requirement do you recommend for Suez Water?

A. As shown on Exhibit RCS-2, Schedule A, page 1, my recommended adjustments in this case result in a recommended revenue requirement for Suez Water of $435,303. This is $589,553 less than the $1,024,856 base rate increase requested by Suez Water in its filing.

Q. Have you presented a reconciliation of Suez Water's request and the Division's recommended adjusted results?

A. Yes. A reconciliation of Suez Water's requested revenue increase and the Division's adjusted results is presented on Exhibit RCS-2, Schedule A, page 2. The estimated revenue requirement impact of each adjustment recommended by Division witnesses, including myself, is shown there.

III. RECOMMENDED ADJUSTMENTS

Q. Would you please discuss each of your sponsored adjustments to SWRI's filing?

A. Yes, I will address each adjustment I am sponsoring below.

Unamortized Rate Case Expense

Q. What is the Company proposing for rate case expense in this proceeding?

A. As discussed on page 10 of the direct testimony of Company witness Katharine Arp, SWRI is proposing to amortize its estimated rate case expense in this proceeding of $181,000 over a three-year period, which results in an annual amortization of rate case expense of $60,333. According to the response to data request DPU 9-22, the Company has included the 13-month average balance of unamortized rate case expense in rate base, net of deferred taxes. As shown on Exhibit 4 (Gil), Schedule 1, from SWRI's filing, for the rate year ending September 30, 2019, the Company has included in its 13-month average rate base, unamortized rate case expense of $87,383, which as noted above, is net of deferred taxes.

Q. Should unamortized rate case expense be allowed in rate year rate base?

A. No. Consistent with the Commission's long-standing precedent, it is inappropriate for SWRI to include unamortized rate case expense in rate year rate base.

Q. Has the Rhode Island Supreme Court affirmed the Commission's long-standing precedent of disallowing unamortized rate case expense from a utility's rate base?

A. Yes. The Rhode Island Supreme Court has affirmed the Commission's long-standing precedent of disallowing unamortized rate case expense from a utility's rate base. Specifically, in *Providence Gas Company v. Malachowski, 656 A.2d 949 at 953 (R.I. 1995),* the Rhode Island Supreme Court affirmed the Commission's long-standing precedent which prohibits unamortized rate case expense from being included in rate base, and which provides for "ratepayers to pay the actual prudently incurred rate case expenses over a period of time, while stockholders pay the carrying costs on the unamortized balance. Such a policy is based upon a sharing of costs between ratepayers and stockholders."

Q. Please explain your adjustment.

A. As shown on Exhibit RCS-2, Schedule B-1, I have removed the 13-month average amount of unamortized rate case expense of $87,383, which is net of deferred income taxes, from the Company's rate base.

Cash Working Capital

Q. Has the Company included an allowance for cash working capital in rate year rate base?

A. Yes. As discussed on page 15 of the direct testimony of Company witness Elda Gil, the Company has included an allowance for cash working capital based on using the formula method, which uses 1/8 of O&M expenses to compute a cash working capital allowance. The Company utilized the formula method in lieu of performing a lead-lag study. As shown on Exhibit 4 (Gil), Schedule 1, the

Company has included a proposed rate year cash working capital allowance of $307,171.

Q. Did the Company explain why it did not perform a lead-lag study in determining an allowance for cash working capital?

A. Yes. In its response to data request DPU 3-2, the Company stated in part:

> Consistent with its rate cases filed in 1999, 2011 and 2013, the Company used the 1/8th of operation and maintenance expenses method. To prepare a detailed lead/lag study can be very costly especially for a small company such as Rhode Island which can be a burden for the customers with increased rate case expenses. The 1/8th method is an acceptable method of estimating cash working capital and is widely used as a proxy.

Q. Do you agree with the Company's use of the Formula Method in its determination of cash working capital?

A. No, I do not. In my opinion, an accurate level of a utility's cash working capital can best be obtained through the use of a detailed lead-lag study. However, as noted in the passage above from the response to DPU 3-2, the Company has utilized the 1/8th formula method of determining an allowance for cash working capital in its last three rate cases prior to the current proceeding, and that method has been accepted by the Commission. However, the results of the formula method in this proceeding need to be adjusted if the Company’s request to convert from quarterly to monthly billing is approved.

Q. Have you made any adjustments to SWRI's cash working capital allowance?

A. Yes. I am recommending three adjustments to SWRI's proposed cash working capital allowance.

The first such adjustment relates to tank painting amortization expense. Specifically, in its response to data request DPU 9-31, the Company stated that it included 1/8th of its tank painting amortization expense of $19,812 (i.e., $2,477) in its proposed cash working capital allowance. However, since the balance of deferred tank painting expense is recorded as a regulatory asset that is included in rate base, the related amortization should be reflected in a manner similar to all other depreciation and amortization expense and should not be included in SWRI's proposed cash working capital allowance. Therefore, I have removed the $2,477 from SWRI's proposed cash working capital allowance.

Q. What is your second recommended adjustment to SWRI's proposed cash working capital allowance?

A. I have reflected the impacts of my adjustments to O&M expense to SWRI's proposed cash working capital allowance. Specifically, reflecting the impact of my recommended adjustments to SWRI's operating expenses would reduce its proposed cash working capital allowance by $27,536.

Q. What is your third recommended adjustment to SWRI's proposed cash working capital allowance?

A. The third adjustment I am recommending to the Company's proposed cash working capital allowance relates to the Company's proposed change to its billing cycle. Specifically, as discussed on pages 18-19 of the direct testimony of Company witness Christopher Jacobs, the Company is proposing to switch all of its customer classes from quarterly to monthly billing. On pages 11-12 of her direct testimony, Company witness Gil states that all but 22 of SWRI's commercial customers are currently billed on a quarterly basis.[1] Ms. Gil states that the change from quarterly to monthly billing will benefit customers as more frequent bills will make budgeting their payments easier versus being faced with larger quarterly bills.

Q. What has the Company stated concerning whether the conversion from quarterly to monthly billing should reduce its cash working capital requirement?

A. In its response to data request DPU 9-50, the Company stated that:

> If the Company performed a full lead/lag study, an adjustment would have been made, however, the Company did not perform such a study. Because the Company is relatively small, in order to keep costs lower, the Company utilized the 1/8th method to calculate cash working capital. As such it is not able to quantify the impact.

Q. Please respond.

A. The fact that SWRI did not perform a lead-lag study should not preclude an adjustment to reduce its cash working capital requirement for the substantially shortened utility service period between billing, and the more frequent billing cycle (monthly versus quarterly), which should speed up the cash flow and thus reduce the amount of the cash working capital allowance. With the conversion to monthly billing, SWRI will recover cash from its customers more frequently than it has been under quarterly billing, thus shareholders would be supplying less cash under

[1] On page 11 of her direct testimony, Ms. Gil states that the 22 commercial customers are currently billed on a monthly basis.

monthly billing than they would under quarterly billing. Because the conversion from quarterly to monthly billing should substantially reduce the cash working capital allowance, I recommend that SWRI's adjusted cash working capital (i.e., after the removal of tank painting amortization expense and the impacts of my adjustments to O&M expense) be reduced by two-thirds to reasonably reflect the impact of the Company switching from quarterly to monthly billing.

Q. Please explain the impacts of your recommended adjustments to cash working capital as discussed above.

A. As shown on Exhibit RCS-2, Schedule B-2, the impacts of my recommended adjustments to cash working capital as discussed above reduces the Company's proposed cash working capital allowance (and rate base) by $213,959.

Q. Do you have any other comments regarding the Company's cash working capital allowance?

A. Yes. If cash working capital is to be calculated using the 1/8th formula, then the proper level of cash working capital reflected for ratemaking purposes should ultimately be based on the pro forma O&M expenses allowed by the Commission versus the $307,171 proposed by SWRI in this proceeding.

Depreciation Expense

Q. Please explain your adjustment for depreciation expense.

A. This adjustment reflects the impacts on depreciation expense of the new depreciation rates for two plant accounts that are being recommended by Division witness Roxie McCullar. Specifically, Ms. McCullar is recommending different depreciation rates than proposed by SWRI for the following two plant accounts: (1) Account 325 - Pumping Plant - Electric Pump, and (2) Plant Account 343 - T&D Plant. As shown on Exhibit RCS-2, Schedule C-1, this adjustment reduces depreciation expense by $9,537.

Q. Have you made an additional adjustment to depreciation expense?

A. Yes. I have made an additional adjustment to depreciation expense, which relates to the amortization of the Company's customer information system ("CIS"). Specifically, as reflected on Company Exhibit 4 (Gil), Schedule 3, the CIS is a single asset that is recorded in plant account 391CB - General Plant Computer Soft Lighthouse, and has a plant balance of $552,856. Plant account 391CB has a depreciation rate of 12.5 percent, which results in annual depreciation expense of $69,107 ($552,856 x 12.5%). There is no component for cost of removal or negative net salvage in the 12.5 percent depreciation rate for this asset. As shown on Exhibit 4 (Gil), Schedule 3, however, the remaining net book value for the CIS is only $76,239 as of the beginning of the rate year, i.e., at September 30, 2018.

If the CIS were to continue to be depreciated at the current annual accrual amount of $69,107, depreciation would be over-charged to customers in the Company’s revenue requirement. Therefore, I am recommending that the remaining net book value for the CIS of $76,239 at September 30, 2018 be amortized over three years, which corresponds with the rate filing cycle proposed by SWRI with regard to its proposed amortization period for rate case expense.

As shown on Exhibit RCS-2, Schedule C-1, page 2, amortizing the remaining net book value of the CIS at September 30, 2018 of $76,239 over three years produces an annual amortization amount of $25,413, and reduces depreciation expense by $43,694.

Q. Please summarize the Division's adjustment to depreciation expense.

A. As shown on Exhibit RCS-2, Schedule C-1, page 1, the $9,537 adjustment previously discussed and the $43,694 adjustment for amortization reduces Suez Water's requested depreciation expense by $53,231.

<u>Wages and Salaries Expense</u>

Q. What is the Company proposing for rate year wages and salaries expense?

A. As discussed on pages 4-5 of the direct testimony of Company witness Katharine Arp, the Company's proposed wages and salaries expense is comprised of four components. The test year in this proceeding is the 12 months ending September 30, 2017. For the first component, SWRI applied a projected 3 percent salary increase to the 2017 hourly rate to reflect wages and salaries for 2018. In addition, another salary increase of 3 percent was applied to projected hourly rates for 2018 to reflect wages and salaries for the rate year ending September 30, 2019. In its response to data request DPU 3-9, the Company stated that salary increases are granted on April 1 of each year.

Q. What are the remaining components of the Company's proposed rate year wages and salaries?

A. The Company also included amounts related to overtime and incentive compensation to its proposed rate year wages and salaries. Specifically, SWRI included a normalization adjustment for overtime which is based on four-year historical average multiplied by the September 30, 2017 hourly rate and increased by the compound wage increase to reflect rate year costs. In addition, the Company reflected incentive compensation by applying a target percentage for each employee based on the Company's Short-Term Incentive Plan guidelines.[2] Finally, the Company proposed normalization adjustments for labor costs transferred and for capitalized labor costs, which was based on a four-year historical average.

Q. Please explain the labor costs transferred.

A. In its response to data request DPU 3-9, SWRI stated that labor transferred in is part of the Company's total payroll expense and relates to charges from the Company's regional office in New York for management, customer service, and finance assistance.

Q. Do you agree with SWRI's proposed rate year wages and salaries expense?

A. Not entirely. I disagree with the Company's use of a four-year historical average to normalize overtime expense and labor transferred in costs, as well as for determining the percentage of labor costs to be capitalized. In each instance, SWRI calculated its four-year average using calendar years 2014, 2015, 2016, and the 12 months ended September 30, 2017 (i.e., the test year).

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[2] The Short-Term Incentive Plan is discussed in further detail in the following section of my testimony.

Q. Why do you disagree with the Company's use of that four-year historical average for normalizing overtime expense and determining the capitalization percentage?

A. I disagree with the Company's use of that four-year historical average for normalizing overtime expense and determining the capitalization percentage because the four-year average includes data from 2014, which is five years removed from the rate year ending September 30, 2019, and thus should be considered stale. Moreover, as it relates to using a four-year historical average to determine the rate year level of wages and salaries to be capitalized, the capitalized rate for 2014 was abnormally low as compared to the capitalized rates associated with 2015, 2016, and the 12 months ended September 30, 2017. Specifically, the 2014 labor capitalization percentage was 18.86 percent whereas the labor capitalization percentages for 2015, 2016, and the 12 months ended September 30, 2017 were 23.82 percent, 23.28 percent, and 26.16 percent, respectively. The Company's inclusion of the 2014 capitalization percentage in the four-year average produces a rate year capitalization percentage of 23.03 percent.

Q. What is your recommendation?

A. I recommend that a three-year historical average utilizing years 2015, 2016, and the 12 months ended September 30, 2017 be used for (1) normalizing the level of overtime expense included in the rate year, (2) normalizing the level of labor transferred in costs included in the rate year, and (3) determining the level of rate year wages and salaries to be capitalized.

Q. What capitalization percentage is produced from using your recommended three-year historical average?

A. As shown on Exhibit RCS-2, Schedule C-2, page 2, the capitalization percentage that is produced from using a three-year historical average is 24.42 percent, which is more representative of SWRI's ongoing operations for the rate year ended September 30, 2019.

Q. Are you recommending another adjustment to SWRI's proposed wages and salaries expense?

A. Yes. As shown on Company Exhibit 3 (Arp), Schedule 2A, page 1, the Company has included rate year wages, incentive compensation, and overtime for a Customer Service/Data Entry Technician position, which totals $54,002. This position was not filled as of the test year ended September 30, 2017. According to Exhibit 3 (Arp), Schedule 2A, the Company has a projected hiring date of October 1, 2018 for this position. However, there is no discussion related to adding this position in Ms. Arp's direct testimony. Since this position has not been filled, I have removed the related cost from wages and salaries.

Q. Please summarize your adjustment.

A. As shown on Exhibit RCS-2, Schedule C-2, my recommendation to use a three-year historical average to (1) normalize the level of overtime expense included in the rate year, (2) normalize the level of labor transferred in costs included in the rate year, and (3) determine the level of rate year wages and salaries to be capitalized coupled with removing the vacant position discussed above reduces the Company's proposed rate year wages and salaries by $48,247.

<u>Incentive Compensation Expense</u>

Q. Does the Company have incentive compensation plans available to its employees?

A. Yes. In its response to data request DPU 3-3, the Company provided a copy of its (1) Short-Term Incentive Plan - Plan Document January 2008 ("ST Incentive Plan"), and (2) 2013 Non-Exempt Non-Union Incentive Program ("Non-Exempt, Non-Union Plan"). The response to DPU 3-3 states that the ST Incentive Plan is comprised of two components, including (1) employee personal goals, and (2) the Company's financial results. In addition, the Non-Exempt, Non-Union Plan is comprised of three components, including (1) environmental health and safety activities, (2) training, and (3) performance. SWRI indicated that the ST Incentive Plan relates to the incentive compensation costs included in its proposed revenue requirement in the current proceeding.

Q. What is the Short-Term Incentive Plan's stated purpose?

A. On page 1 of the ST Incentive Plan document, under "Purpose", it states:

> The Short Term Incentive Plan (STIP) is an annual compensation plan that supports United Water's[3] business objectives by:
>
> - Providing an annual incentive strategy that **drives performance towards objectives critical to creating shareholder value**.

[3] As discussed on page 3 of SWRI witness Christopher Jacobson's direct testimony, in 2015, United Water Rhode Island ("UWRI") was changed to Suez Water Rhode Island.

> - Offering competitive cash compensation opportunities to all eligible employees.
>
> - Awarding outstanding achievement among employees who can directly impact United Water's results.
>
> - Providing cash awards for both qualitative and quantitative results.
>
> - Providing cash compensation opportunities for making sound business decisions **that impact the Company's financial performance and the overall success of Suez**.
>
> (Emphasis supplied)

Q. Please briefly describe the ST Incentive Plan.

A. As discussed on pages 1-2 of the ST Incentive Plan document, the ST Incentive Plan is based on two different measures of performance, including financial and personal performance. With regard to the financial performance measure, the ST Incentive Plan document states:

> Each year, Suez Environment and United Water's Compensation Advisory Committee determine financial measures and target performance levels that will form the basis for measuring success under STIP. Each objective is assigned a weight based on the employee's job/salary grade.

In addition, as it relates to the personal performance measure, the ST Incentive Plan document states:

> As a part of the Performance and Development Review (PDR) process, employees have specific annual objectives that support the attainment of departmental or organizational objectives. These objectives form the basis for the personal objective portion of the STIP. Managers have the flexibility to set the weight of each personal objective in accordance with the plan's guidelines.

Q. Has SWRI included incentive compensation expense related to the STIP in its rate year cost of service?

A. Yes. The response to data request DPU 3-3 states that the Company included incentive compensation expense related to the STIP of $61,479 in the rate year ending September 30, 2019. Of this amount, $29,176 is direct charged to SWRI employees and $32,304 is allocated to SWRI from Suez Water Management & Services ("SWM&S").

Q. Has SWRI identified the portion of the STIP that is associated with meeting the Company's financial goals?

A. Yes. In its response to DPU 3-3, the Company provided Attachment B, which is replicated below, and which shows that on average, the portion of the STIP that is based on the Company achieving its financial goals is 40 percent.

Metric	Corporate M&S Grade 20-23	Corporate M&S Grade 13-19	Regulated & UWES M&S Grade 20-23	Regulated & UWES M&S Grade 13-19	Average
Financial Objective %	50%	30%	50%	30%	40%
Non-Financial Objective %	50%	70%	50%	70%	60%
Total	100%	100%	100%	100%	100%

Source: DPU 3-3, Attachment B

Q. Has SWRI included incentive compensation expense related to long-term incentive compensation in its rate year cost of service?

A. Yes. The response to DPU 3-3 indicates that SWRI has included long-term incentive compensation ("LTIP") totaling $10,145 in its rate year cost of service. This entire amount is allocated to SWRI from SWM&S.

Q. **Has SWRI identified the portion of the LTIP that is associated with meeting the Company's financial goals?**

A. It appears that 100 percent of the LTIP is associated with meeting the Company's financial goals. In addition to the 40 percent average discussed above as it relates to the STIP, the response to DPU 3-3(e) referred to the direct testimony that was filed by Division witness Thomas Catlin in the Company's last rate case in Docket No. 4434. Specifically, on page 17 (lines 8-9) of his direct testimony in that prior proceeding, Mr. Catlin stated:

> In addition, M&S fees include $7,612 of LTIP payments, which are based 100 percent on achieving financial goals.

Q. Are you recommending an adjustment to the level of incentive compensation related to the STIP and LTIP that is included in the rate year cost of service?

A. Yes. I recommend that 40% of the incentive compensation related to the STIP and 100 percent of the LTIP that is included in the rate year be borne by shareholders.

Q. What is the basis for your recommendations to (1) remove 40 percent of incentive compensation related to the STIP, and (2) 100 percent of incentive compensation related to the LTIP?

A. The basis for my recommendations is that incentive compensation expense that is tied to a utility's financial performance should not be borne by ratepayers. Specifically, the portion of incentive compensation expense that is directly attributable to meeting financial performance goals is not properly recoverable from ratepayers for several reasons. First, if the financial goals are set properly, achieving the necessary performance should be self-supporting. That is, measures that achieve additional cost savings, improve sales, or otherwise improve the financial results of the Company should provide the income necessary to fund the awards. Second, the payouts for financial goal achievement can be distinguished from incentive compensation that is measured for improving the quality of service, efficiency, or safety goals. Finally, the incentive to improve financial performance is not necessarily consistent with ratepayers' interests.

Q. Please explain your recommended adjustment for Incentive Compensation expense related to the STIP and LTIP.

A. As shown on Exhibit RCS-2, Schedule C-3, this adjustment reduces rate year O&M expense by $35,337 to reflect the removal of (1) 40 percent of incentive compensation expense that on average, relates to the financial goals associated with the STIP, and (2) 100 percent of incentive compensation that relates to the financial goals associated with the LTIP.

Q. Is there a related adjustment to payroll tax expense?

A. Yes. As discussed below, my recommended adjustment to incentive compensation expense results in a related adjustment to payroll tax expense as shown on Exhibit RCS-2, Schedule C-4.

<u>Payroll Tax Expense</u>

Q. Please explain your adjustment to payroll tax expense for the rate year.

A. My recommended adjustment to SWRI's payroll tax expense is made in conjunction with the adjustments that I am recommending related to (1) wages and salaries expense; and (2) incentive compensation expense. Based upon those recommended adjustments, as shown on Exhibit RCS-2, Schedule C-4, I have reduced SWRI's payroll tax expense by $6,394.

<u>Property Tax Expense</u>

Q. Please explain the Company's proposed adjustment to rate year property tax expense.

A. As discussed in the direct testimony of Company witness Arp, the Company calculated a four-year historical average change in actual property taxes paid from prior years through 2017. From this calculation, the Company determined an average annual percentage of 5.75%, which SWRI applied to 2018 and to the rate year ending September 30, 2019 to derive the projected property tax expense amount. As shown on Exhibit 3 (Arp), Schedule 18, the Company's proposed adjustment increases property tax expense for the rate year by $51,210.

Q. Do you agree with the Company's proposed methodology for determining rate year property tax expense?

A. Not entirely. I agree with the use of an historical-based average methodology for determining rate year property tax expense. However, as stated above with respect to my recommended adjustment to wages and salaries, I disagree with the Company’s use of a four-year historical average since such an average includes property taxes from 2014, which is five years removed from the rate year ending September 30, 2019, and thus should be considered stale.

Q. Please explain your adjustment to property tax expense.

A. I have calculated rate year property tax expense in a manner similar to the Company except that I have used a three-year historical average change in actual property taxes paid through 2017. From this calculation, I determined an average annual percentage of 4.31%, which I applied to derive the projected rate year property tax expense. As shown on Exhibit RCS-2, Schedule C-5, my recommended adjustment reduces the Company's requested rate year property tax expense by $11,082.

<u>Transportation and Vehicle Lease Expense</u>

Q. Please explain the Company's adjustment to rate year transportation and vehicle lease expense.

A. As discussed on page 8 of the direct testimony of Company witness Arp, the Company's proposed adjustment to transportation and vehicle lease expense included the use of four-year historical averages utilizing years 2014, 2015, 2016, and the test year ended September 30, 2017 to calculate rate year levels expenses related to fuel, maintenance and repair, insurance, and other miscellaneous. In addition, SWRI updated lease costs based on a combination of actual leased vehicles and projected costs for lease replacements. As shown on Company Exhibit 3 (Arp), Schedule 10, the Company's proposed adjustment increases transportation and vehicle lease expense by $12,002.

Q. Do you agree with the Company's proposed adjustment?

A. Not entirely. I disagree with the Company's use of the four-year averages for calculating the rate year expenses identified above as follows:

As it relates to fuel expense, the 2014 amount used in the four-year average is substantially higher than in the subsequent years. In its response to data request DPU 3-14, SWRI stated that the 2014 fuel expense was higher for two reasons, including (1) the Company had 10 vehicles in 2014 whereas there are only seven vehicles currently, and (2) fuel prices has dropped sharply since 2014.

As it relates to maintenance and repair expense, the test year amount was significantly higher than the preceding years in the four-year average. The response to DPU 3-14 stated that the reason for this is that there was an accident with one of the Company's vehicles, which SWRI opted to have repaired versus replacing, thus the higher maintenance and repair expense in the test year.

As it relates to insurance and other miscellaneous expense, the test year amounts were substantially lower than the preceding years. With regard to insurance expense, the response to DPU 3-14 stated that this was due to an annual reserve adjustment that was booked to the general ledger. With regard to other miscellaneous expense, the response to DPU 3-14 stated that SWRI has not yet been billed for 2017 Rhode Island personal property tax.

Q. What is your recommendation with regard to the calculating the rate year amounts for fuel, maintenance and repair, insurance, and other miscellaneous expense?

A. I recommend that for each such expense, a three-year average be used to calculate the rate year amounts. Specifically, for fuel expense I recommend using years 2015, 2016, and the test year ended September 30, 2017.

For maintenance and repair, insurance, and other miscellaneous expense, I recommend using 2014, 2015, and 2016 for the three-year averages. As discussed elsewhere in my testimony, I have recommended removing 2014 data from the calculation of historical averages due to the data being stale. As shown on Exhibit RCS-2, Schedule C-6, for insurance and other miscellaneous, the 2014 expense is higher than the 2016 expense. Given the abnormal test year amounts for repairs and maintenance, insurance, and other miscellaneous expense, using the 2014 through 2016 data and not using the test year amounts, provides a more reasonable three-year average for calculating the rate year amounts for these expenses.

Q. Is there another aspect of the Company's proposed expense that should be adjusted?

A. Yes. Some of the lease costs that SWRI is proposing be included in its determination of rate year lease expense should be adjusted. Specifically, SWRI has included monthly lease expense for two vehicles in which the leases expired in 2017. In addition, SWRI increased the monthly lease costs for two other vehicles by nearly double what they currently are. In its response to DPU 3-14, the Company stated that in both cases, it will be replacing the existing vehicles with new vehicles. However, both of these existing leases do not expire until August 31, 2018, so the Company's proposed increases to monthly lease expense are not known and measurable at this time. Therefore, I recommend that the existing monthly lease payments for these two vehicles be used in the determination of rate year lease expense.

Q. Please summarize your adjustment.

A. As shown on Exhibit RCS-2, Schedule C-6, my recommended adjustments to (1) use the three-year historical averages described above to determine rate year fuel, maintenance and repair, insurance and other miscellaneous expense, and (2) eliminate and/or reduce monthly lease payments for certain vehicles in the determination of rate year lease expense, reduces O&M expense by $13,592.

<u>Management & Services ("M&S") Expense</u>

Q. Please summarize the types of services that are provided to SWRI by Suez Water Management & Services, Inc. ("SWM&S").

A. The Company provided a copy of the Agreement Between Suez Water Management & Services Inc. and Suez Water Rhode Island in MFR 2.89(e). Article 1 of that agreement states that SWM&S provides services in the following areas to SWRI: Executive Services, Financial Planning, Accounting and Tax, Treasury, Internal Audit, Information Technology, Legal, Engineering and Technical Services, Procurement, Corporate Communications, Internet Services, Human Resources, Regulatory Business, Revenue Management, Facilities, Business Development, Environmental Health & Safety, Customer Care, General and Special Services.

Q. Please explain the Company's proposed adjustment to rate year management & services ("M&S") expense.

A. As discussed on page 10 of the direct testimony of Company witness Arp, the Company's proposed rate year M&S expense was determined by applying SWRI's projected wage increase of 6.09 percent to the test year amount. As shown on Company Exhibit 3 (Arp), Schedule 14, the Company's proposed adjustment results in rate year M&S expense totaling $509,952.

Q. Do you agree with the Company's proposed methodology for determining the rate year level of M&S expense?

A. No. I do not agree with the Company's proposed methodology for determining the rate year level of M&S expense. Applying the projected compound wage increase of 6.09 percent to the test year amount of M&S expense produces an amount that is substantially higher than the amounts for M&S expense that SWRI has historically incurred since 2014.

Q. Did SWRI provide historical levels of M&S expense incurred?

A. Yes. As shown on Company Exhibit 3 (Arp), Schedule 14A, SWRI provided the historical amounts of M&S expense for the years 2014, 2015, 2016, and the test year ended September 30, 2017. In addition, the response to data request DPU 9-37 included the Company's M&S expense from calendar 2017 as well.

Q. How do these historical levels of M&S expense compare to the amount proposed by the Company for the rate year ended September 30, 2019?

A. The historical levels of M&S expense in all of the years noted are substantially lower than the amount proposed by SWRI for the rate year. Moreover, these expenses have decreased from 2016 to 2017.

Q. Has SWRI provided actual monthly allocations of M&S expense for 2018?

A. Yes. In its response to data request DPU 9-37, SWRI provided actual monthly allocations of M&S for the first four months of 2018. As shown in the table below, annualizing these amounts over the entire 12 months of 2018 results in M&S expense of $457,113:

Date	Amount
January 2018	$ 43,718
February 2018	$ 35,370
March 2018	$ 36,346
April 2018	$ 36,937
Subtotal	$ 152,371
Divided by 4 Months	4
4 Month Average	$ 38,093
Multiplied by 12 Months	12
Annualized 2018 M&S Expense	$ 457,113
Source: DPU 9-37	

This is closer to the average historical levels of M&S expense incurred by the Company for the years 2015 through 2017 than the Company's requested level of $509,952.

Q. What is your recommendation?

A. I recommend that a three-year historical average utilizing calendar years 2015, 2016, and 2017 be used to determine the rate year level of M&S expense.[4] This results in rate year M&S expense of $445,215.

Q. Please summarize your adjustment.

A. As shown on Exhibit RCS-2, Schedule C-7, my recommended adjustment to M&S expense using a three-year historical average reduces the Company's requested expense by $64,736.

Chemical Expense

Q. Please explain the Company's adjustment to rate year chemical expense.

A. As discussed on pages 6-7 of the direct testimony of Company witness Arp, the Company's projected chemical expense was calculated by computing the chemical unit price for each chemical and multiplying it by total projected usage for the rate year. Specifically, the chemical unit price was based on the Company's actual price bid for 2018 adjusted for inflation. In addition, the total usage is based on projected water produced multiplied by chemical usage per million gallons based on a four-year average using calendar years 2014, 2015, 2016, and the test year ended September 30, 2017. Finally, the Company adjusted the projected water produced by the non-revenue water percentage, which the Company calculated by utilizing a four-year average of non-revenue water percentages using the same periods noted

[4] The 2014 M&S expense of $259,208 was included in Exhibit 3 (Arp), Schedule 14, but this amount is substantially lower than amounts incurred in each year 2015 through 2017, thus was not used in my recommended use of a three-year historical average to determine the rate year level of M&S expense.

above. As shown on Company Exhibit 3 (Arp), Schedule 5, the Company's proposed adjustment decreases chemical expense by $13,942.

Q. Do you agree with the Company's proposed methodology for calculating the rate year level of chemical expense?

A. Not entirely. I agree with the use of an historical average for calculating the rate year level of chemical expense. However, similar to my recommended adjustment to wages and salaries expense, I disagree with SWRI's use of a four-year historical average which includes 2014 data to calculate (1) projected usage for the rate year and (2) the non-water revenue percentage used in the Company's proposed adjustment for billed consumption.

Q. Did you note an error in the Company's calculation of its proposed non-revenue water percentage?

A. Yes. The Company's calculation of its proposed non-revenue water percentage, which it applied to billed consumption, is shown on Exhibit 3 (Arp), Schedule 5A. Upon reviewing the electronic version of this schedule, I noted that while SWRI included non-revenue water percentages for 2014, 2015, 2016, and the test year ended September 30, 2017, the Company calculated its average non-revenue water percentage of 3.05 percent by dividing these four percentages by three instead of four, which skewed the result. If this average was calculated correctly, the non-revenue water percentage would have been 2.29 percent.

Q. What is your recommendation for calculating SWRI's rate year chemical expense?

A. I recommend that a three-year historical average utilizing calendar years 2015, 2016, and the test year ended September 30, 2017 be used to calculate (1) projected usage for the rate year and (2) the non-water revenue percentage. This methodology results in rate year chemical expense of $46,283.

Q. Please summarize your adjustment.

A. As shown on Exhibit RCS-2, Schedule C-8, my recommended adjustment to chemical expense using a three-year historical average increases the Company's estimated rate year chemical expense by $1,113.

<u>Power Expense</u>

Q. Please explain the Company's adjustment to rate year power expense.

A. As discussed on pages 5-6 of the direct testimony of Company witness Arp, SWRI computed purchase power costs by taking the projected total kWh usage and increasing it by calculated rate year kWh for commodity and distribution using a four-year average. This average was applied to the total rate year water produced to determine total rate year kWh usage and was further adjusted by the non-revenue water percentage discussed in the previous section of my testimony regarding chemical expense. In addition, the kWh average commodity cost was calculated by applying the contract price from Engie Resources, LLC, which SWRI then increased by 15 percent for surcharges and taxes. Moreover, SWRI's projected rate year kWh price for transmission and distribution was calculated by taking the

National Grid actual average rate per kWh and increasing it by 10.21 percent, which Ms. Arp states is based upon the rate case filed on November 27, 2017 in RIPUC Docket No. 4770. Finally, the Company adjusted Other Utilities Power by using a four-year average and adjusting for inflation. As shown on Company Exhibit 3 (Arp), Schedule 4, the Company's proposed adjustment increases rate year power expense by $81,864.

Q. Do you agree with the Company's proposed methodology for calculating the rate year level of power expense?

A. Not entirely. I agree with the use of historical averages for calculating the rate year level of power expense. However, similar to other Company proposed adjustments in which an average was used, I disagree with SWRI's use of a four-year historical average which includes 2014 data for the reasons previously discussed. As it relates to power expense, I disagree with using a four-year average to calculate (1) the rate year kWh for commodity and distribution, (2) the non-water revenue percentage used in the Company's proposed adjustment for billed consumption, and (3) Other Utilities Power.

Q. Do you take issue with another aspect of the Company's proposed adjustment to power expense?

A. Yes. I take issue with the Company's proposal to increase the National Grid actual average rate per kWh by 10.21 percent. As noted above, Ms. Arp stated that including the 10.21 percent increase was based on National Grid's rate case that was filed on November 27, 2017 in RIPUC Docket No. 4770. In its response to data request DPU 3-11, the Company stated that the 10.21 percent increase is based on National Grid's proposed rates (based on the new federal tax law) and that the Company does not know when the Commission will issue an Order in that proceeding. Because the 10.21 percent increase proposed by SWRI is based on National Grid's proposed rates and because that case is still pending before the Commission, the amount is not known and measurable at this time and should therefore be removed. As of the date of my testimony being filed, the National Grid rate case is still pending before the Commission. Specifically, a settlement has been filed but it has not been approved by the Commission. If the Commission approves a rate increase for National Grid and the amount becomes known while the Suez Water rate case is pending, it can be factored in at a later point in the Suez Water rate case.

Q. What is your recommendation for calculating SWRI's rate year power expense?

A. I recommend that a three-year historical average utilizing calendar years 2015, 2016, and the test year ended September 30, 2017 be used to calculate (1) the rate year kWh for commodity and distribution, (2) the non-water revenue percentage used in the Company's proposed adjustment for billed consumption, and (3) Other Utilities Power. In addition, as discussed above, I have removed the 10.21 increase that SWRI added to the National Grid actual average rate per kWh.

Q. Please summarize your adjustment.

A. As shown on Exhibit RCS-2, Schedule C-9, my recommended adjustment to power expense using a three-year historical average and removing the 10.21 percent increase discussed above reduces O&M expense by $22,199.

Interest Synchronization

Q. Please explain your adjustment to interest synchronization.

A. This adjustment modifies the Company's interest synchronization adjustment to reflect my recommended rate base and the weighted cost of debt recommended by Division witness Kahal. As shown on Exhibit RCS-2, Schedule C-10, federal income tax expense is increased by $1,348 for interest synchronization.

Amortization of TCJA-Related Regulatory Liability

Q. Please explain your adjustment to the amortization of the TCJA-related Regulatory Liability.

A. This adjustment is shown on Exhibit RCS-2, Schedule C-11 and addresses the amortization of the Tax Cuts and Jobs Act-related Regulatory Liability. As shown on Schedule C-11, page 1, line 12, income tax is reduced by $98,867 for the amortization of the TCJA-related regulatory liability. This is a larger reduction by $65,263 compared with the $33,604 amount of reduction that had been reflected by Suez Water in its application at Company Exhibit 4 (Cagle), Schedule 5C. Additional details of how the TCJA has impacted the Company and the components of the TCJA-related Regulatory liability are presented in Section IV of my testimony, below.

IV. THE TAX CUTS AND JOBS ACT OF 2017

Q. Please summarize some of the primary impacts of the Tax Cuts and Jobs Act.

A. Under the TCJA, the new federal corporate income tax rate is 21%. The new lower federal income tax rate will significantly reduce Suez Water's federal income tax expense. The TCJA also requires that accumulated deferred income taxes be revalued at the new corporate income tax rate of 21 percent. The ADIT was previously accumulated on the Company's books using the former statutory federal corporate income tax rate of 35 percent. This revaluation of ADIT creates excess ADIT, which the Company has indicated it recorded as a Regulatory Liability in account 253. The excess ADIT will need to be separated into "protected" and "non-protected" components. The "protected" excess ADIT is subject to normalization requirements, and therefore there is very limited regulatory commission discretion as to the amortization of the "protected" excess ADIT. In contrast, the regulatory commission has wide discretion as to how the "non-protected" excess ADIT should be amortized.

Since the federal corporate income tax rate was reduced on January 1, 2018 and new rates for the Company in this rate case will not go into effect until some later point in 2018[5], the amount of federal income tax savings from January 1, 2018 through the rate effective date is being accumulated by Suez Water into a Regulatory Liability account. The amount of that component of the TCJA-related Regulatory Liability will also need to be addressed in this rate case.

[5] Both Suez Water and the Division are currently assuming a rate effective date of October 1, 2018, as reflected in our respective calculations of the TCJA-related Regulatory Liability amortization.

The TCJA has other impacts on regulated utilities, such as Suez Water, including changes to the taxation of CIAC and terminating bonus tax depreciation for public utility property placed into service after September 27, 2017. However, the above noted impacts related to the reduction in the federal income tax rate and addressing the excess ADIT appear to be the primary ones which need to be taken into account in determining the Company's revenue requirement in the current rate case.

<u>Reduction in the Federal Corporate Income Tax Rate</u>

Q. How has the Company reflected the new 21 percent federal corporate income tax rate in the calculation of income tax expense in its application?

A. On its Exhibit 3 (Gil), Schedule 21, the Company has calculated income tax expense using the new 21 percent federal corporate income tax rate that became effective on January 1, 2018.

Additionally, as reproduced on my Exhibit RCS-2, Schedule A, page 1, on line 6, in calculating the amount of additional revenue needed based on the net operating income deficiency, the new 21 percent federal corporate income tax rate has effectively been incorporated into the gross revenue conversion factor that was used by Suez Water and that is being used in the Division's calculation of the revenue requirement.

The amortization of the Regulatory Liability related to 2018 federal income tax savings from January 1, 2018 through the rate effective date is also an issue that needs to be addressed in the current Suez Water rate case. I address that issue below and as shown on Exhibit RCS-2, Schedule C-11.

Federal Income Tax Savings from January 1, 2018 through the Effective Date of New Rates

Q. How has the Company reflected the amount of the Regulatory Liability related to federal income tax savings from January 1, 2018 through the effective date of new rates?

A. The Company's Exhibit 4 (Cagle), Schedule 5C contains detail that shows that the Company originally estimated an amount of $129,640 of federal income tax savings from January 1 through September 30, 2018, its estimated effective date of new rates. The Company has reflected that as part of its proposed TCJA-related Regulatory Liability, which the Company proposes to amortize over 50 years. The Company has thus proposed to reduce rate year income tax expense by $2,593, relating to its proposed 50-year amortization of this component of its TCJA-related Regulatory Liability.

Q. Has the Company identified the amount of federal income tax savings by month, starting with January 1, 2018, using actual amounts through April 2018?

A. Yes. The Company's response to DPU 9-7 shows that the Company anticipates $46,195 federal income tax savings (including the tax gross-up) through April 2018 and has presented that amount as a Regulatory Liability. Additionally, the Company's response to DPU 9-8 presents the pre-tax net operating income that the Company expects in each month of 2018 from May through December, including calculations of federal income tax expense at the previous 35 percent rate and at the new 21 percent rate.

Q. Have you summarized that information on a Schedule showing the cumulative amounts of Regulatory Liability for 2018 federal income tax savings by month?

A. Yes. Exhibit RCS-2, Schedule C-11, page 2, summarizes the information provided by the Company in response to DPU 9-7 and 9-8 showing the regulatory liability at April 30, 2018 and as estimated by the Company for each remaining month of 2018 through December 31, 2018. As shown there, the amount of Regulatory Liability for federal income tax savings from January 1 through September 30, 2018 (without the gross-up) is $199,855 and is $252,983 with the gross-up.

Q. Should the Regulatory Liability for 2018 federal income tax savings be considered in the current Suez Water rate case even if the rate case determines that the Company had not been earning its authorized rate of return?

A. Yes. The 2018 federal income tax savings has occurred because of a major change in federal income tax law. The 2018 federal income tax savings can be measured and should be reflected in the current rate case whether or not Suez Water had been earning its previously authorized rate of return in 2018. This issue has arisen in another recent utility rate case, and was resolved by amortizing the cumulative federal income savings.

Q. You mentioned that a utility may take a position that reflects for ratemaking purposes its Regulatory Liability for 2018 income tax savings is not warranted because they were not earning their authorized rate of return. Have you seen a similar issue arise in another recent utility rate case?

A. Yes. In a recent Hawaiian Electric Company ("HECO") rate case,[6] an issue concerning 2018 income tax savings was considered. HECO had claimed that it was not earning its authorized rate of return, and thus no provision for recognizing income tax savings from January 1 through the effective date of new rates was warranted.

Q. What is the current status of that issue in that case?

A. A proposed settlement filed in that case that incorporates, among other things, a provision to reduce interim rates to reflect the revenue requirement reduction impact of amortizing over a three-year period the accumulated Daily Revenue Impact of 2017 Tax Act savings from January 1, 2018 to the effective date of the reduced interim rates. This provision is designed to capture and start flowing back to the utility's ratepayers the impact of daily income tax savings from January 1, 2018 through the effective date of new rates.

Q. What is your recommendation for the rate case treatment of the Suez Water Regulatory Liability for 2018 federal income tax savings?

[6] See, Hawaii Public Utilities Commission, Docket No. 2016-0328.

A. The amount of this Regulatory Liability, related to the federal income tax savings from January 1, 2018 through the effective date of new rates, should be reflected in the current Suez Water rate case by amortizing the amount as of the effective date of new rates over a reasonable period, such as the one that is being used for the amortization of rate case expense.

Q. Have you presented an illustrative calculation of how the amortization of the Regulatory Liability related to 2018 federal income tax savings could work?

A. Yes. As noted above, the Company's responses to DPU 9-7 and 9-8 can be used to estimate the amount of income tax savings from January 1, 2018 through the effective date of new rates in this case. Depending on the effective date for new rates in this case, an amortization of that tax savings amount reflected in that Regulatory Liability can be amortized over an appropriate period. As an appropriate amortization period, a relatively short period such as a three-year period used in a recent HECO rate case settlement noted above, and the three-year period being used by Suez Water for the amortization of rate case expense, should be considered. The amortization period determination could also take into consideration the Company's typical rate case filing cycle, and the period being used to amortize rate case expense.

Q. Have you prepared a calculation of the recommended adjustment using amounts available at this time?

A. Yes. Exhibit RCS-2, Schedule C-11, pages 1 and 2 show the related adjustment. The Company's proposed amortization of an estimated amount of 2018 federal income tax savings from January 1 through September 30 for a Regulatory Liability of $129,640 amortized over 50 years for an annual amortization of $2,593 as the reduction to income tax expense, is shown on Schedule C-11, page 1, line 22. Instead of that, I recommend that the updated amount of estimated federal income tax savings from January 1 through September 30, 2018 of $199,855 be amortized over three years for an annual amortization of $66,618 to reduce rate year income tax expense by $64,025, as shown on Schedule C-11, page 1, line 22.

This, in combination with the amortization of unprotected excess ADIT (discussed below), results in a reduction to rate year income tax expense that is $65,263 larger than the Company's proposal.

<u>Accumulated Deferred Income Taxes ("ADIT") and Excess ADIT</u>

Q. What is your current understanding of how excess federal ADIT for regulated public utilities can be addressed?

A. My current understanding is that regulated public utilities will be required to identify the portions of their ADIT balances that represent "excess" ADIT based on recalculations using the difference between the old federal income tax rate (“FIT”) (typically 35%) under which the ADIT was accumulated and the new federal corporate rate of 21%. Basically, utility ADIT must be revalued at the new FIT rate. All *non-property* related ADIT (accounts 190 and 283 for water utilities) will be reduced. To ensure that these benefits are passed to customers, the regulator should require that the reduction be deferred in a net regulatory liability. *Property* related ADIT (account 282 for water utilities) will also need to be revalued at the new FIT rate. IRS normalization requirements will apply to the portion of the property related ADIT that relates to the use of accelerated tax depreciation (including federal bonus tax depreciation).

Regulated public utilities (as do other business taxpayers) typically compute tax depreciation using the Modified Accelerated Cost Recovery System ("MACRS"), which is the current tax depreciation system in the United States. Under this system, the capitalized cost (basis) of tangible property is recovered over a specified life by annual deductions for depreciation. The differences between the use of accelerated tax depreciation to produce depreciation deductions for federal income tax purposes and the use of book depreciation (typically some form of straight-line depreciation) are accounted for, and the tax impacts are accumulated as ADIT for accounting and ratemaking purposes.

It is expected that the excess ADIT related to the use of accelerated tax depreciation will result in "protected" excess ADIT balances for at least a portion of the utility's property related ADIT, e.g., the ADIT recorded in account 282. That "protected" ADIT will be subject to normalization requirements, which will govern how it can be flowed back to ratepayers. The Tax Act specifically provides that the average rate assumption method ("ARAM") must be used for the protected portion of ADIT, although an alternative method is permitted if adequate records are not available to compute the ARAM.

In contrast, the flow back of the "unprotected" portion of the excess ADIT will be up to the discretion of the regulatory authority. Unprotected ADIT is not subject to normalization requirements and will be revalued at the lower 21% FIT rate. A regulatory liability may need to be established to ensure that the un-protected excess ADITs are captured and can be passed back to customers.

Q. Please elaborate on the normalization requirement.

A. As described above, the Tax Act reduced the federal corporate income tax rate to a flat 21%. Public utilities are required, as a condition of using MACRS (accelerated tax depreciation) to use normalization accounting under which depreciation for ratemaking purposes does not reflect the accelerated depreciation under MACRS. The normalization requirements address how the "excess" ADIT balances related to the use of accelerated tax depreciation on utility property can be flowed back. Generally, the flow-back of such "protected" excess ADIT balances must occur over the remaining life of the related utility property.

Specifically, the Tax Act provides that public utilities subject to the normalization method of accounting are not treated as applying the normalization method for any public utility property for purposes of Code Sec. 167 or Code Sec. 168 if they reduce their excess tax reserves resulting from the lower tax rate in computing their cost of service for ratemaking purposes and for purposes of reflecting operating results in their regulated books of account, more rapidly or to a greater extent than the amount the reserve would be reduced under the average rate assumption method. (Tax Act §13001(d)(1)) For this purpose, the excess tax reserve is the reserve for deferred taxes, described in Code Sec. 168(i)(9)(A)(ii) as in effect on the day before the FIT rate reductions take effect (Tax Act §13001(d)(3)(A)(i)), minus the amount that would be the balance in the reserve if the amount of the reserve were determined by assuming that the Tax Act corporate rate reductions were in effect for all prior periods. (Tax Act §13001(d)(3)(A)(ii))

Q. Has the Company presented calculations purporting to identify its excess ADIT as of December 31, 2017?

A. Yes. As I have summarized on Exhibit RCS-2, Schedule C-11, page 3, the Company's response to DPU 9-1 identifies the components of the Company's ADIT balance as of December 31, 2017 to be $3,062,315 before TCJA impacts. The Company's response to DPU 9-1 also identifies amounts of adjustment for restating the December 31, 2017 ADIT balances at the new federal income tax rate of 21 percent of $1,224,926 for the new federal income tax rate and $325,613 for the gross-up using the new 21 percent federal income tax rate. The sum of these amounts is $1,550,539, which Suez Water shows on its response to DPU 9-1 as the amount of its Regulatory Liability in Account 25316.

Q. Have you prepared a Schedule using the information from Suez Water's response to DPU 9-1 to identify and show the amounts of Excess ADIT that are contained in the Regulatory Liability amount that Suez Water has recorded in Account 25316?

A. Yes. Exhibit RCS-2, Schedule C-11, page 3, uses the amounts from the Company's response to DPU 9-1 to show the details of the Company's December 31, 2017 ADIT liability balance of $3,062,315. Schedule C-11, page 3, also shows the restated December 31, ADIT liability balance at the new 21 percent federal income tax rate of $1,837,389 and the excess ADIT liability (i.e., Regulatory Liability) of $1,224,926 by component. The gross-up on the excess ADIT Regulatory Liability of $325,613 is also shown on that Schedule.

Q. Have you also presented the Regulatory Liability components into the categories of "protected" and "non-protected" excess ADIT?

A. Yes. The Regulatory Liability components are shown in the categories of "protected" and "non-protected" excess ADIT on Exhibit RCS-2, Schedule C-11, page 3, in columns D and E, before the tax gross-up, and in columns F and G after the tax gross-up. The total excess ADIT with the tax gross-up of $1,550,539 is the same amount calculated by Suez Water, but the breakout between “protected” and “non-protected” is different, due to three items.

Q. Does it appear that the Company's response to DPU 9-1 has properly classified all of the components of the December 31, 2017 excess ADIT between the "protected" and "non-protected" categories?

A. No. In Account 282, the Company has properly designated the excess ADIT related to the use of accelerated tax depreciation, i.e., the balance in account 28203 ("Def FIT-MACRS") as protected. However, the other items, which are in account 283, do not appear to be related to the use of accelerated tax depreciation for federal income tax purposes and thus do not appear to represent "protected" excess ADIT. Three items in particular appear to have been misclassified as “protected” by the Company. Those items are:

- account 28301 - Deferred FIT - Tank Painting,
- account 28308 - Deferred FIT - Cost of Removal, and
- account 28312 - Deferred FIT -AFUDC Equity.

Q. Please explain your concerns with the Company's classification of each of the above-noted three items as "protected" excess ADIT.

A. The Company has not demonstrated that it is using accelerated tax depreciation for tank painting. That item is amortized on a straight line basis for regulatory purposes. Since the tank painting does not appear to involve the use of accelerated depreciation for federal income tax purposes or fall under Internal Code Sections 167 or 168, it does not appear to be protected. Moreover, the ADIT for that item is recorded in a sub-account (28301) of account 283, which is for Other ADIT, not property-related ADIT. Typically, the other ADIT that is recorded in account 283 is not subject to normalization requirements and is considered non-protected.

Similarly for the Deferred FIT for Cost of Removal that Suez Water records in sub-account 28308, the federal income tax deduction for cost of removal fall under Internal Code Sections 167 or 168, which involve the use of accelerated depreciation for federal income tax purposes, does not appear to be protected. Cost of removal is deducted for federal income tax purposes when the amounts are spent and the ADIT for that item is recorded in account 283, which is for Other ADIT. The excess ADIT related to cost of removal thus belongs in the “non-protected” category.

The Deferred FIT for AFUDC Equity is a permanent book-tax difference because the equity return is not capitalized or depreciated for federal income tax purposes, but is for book accounting purposes. Equity AFUDC is capitalized for book accounting purposes and is depreciated. However, since equity AFUDC is never capitalized for federal income tax accounting purposes, it does not become part of the tax basis of the asset for FIT purposes and no tax depreciation is calculated on equity AFUDC. Thus, the excess ADIT related to equity AFUDC does not relate to the use of accelerated tax depreciation for federal income tax purposes and is therefore not properly considered "protected" or subject to tax normalization requirements. The equity AFUDC item should therefore be categorized as “non-protected” excess ADIT.

Q. On Exhibit RCS-2, Schedule C-11, how have you categorized the above-noted items?

A. On Exhibit RCS-2, Schedule C-11, page 3, I have categorized the excess ADIT related to the use of accelerated tax depreciation, i.e., the Deferred FIT - MACRS, as "protected" and the remaining items as "non-protected."

Q. What is your current understanding of the required regulatory treatment for "protected" excess ADIT?

A. As described above, "protected" excess ADIT must comply with normalization requirements. The TCJA specifies that the average rate assumption method should be used if adequate records are available; otherwise an acceptable alternative method that complies with normalization requirements can be used.

Q. What software does the Company use to track the tax basis and tax depreciation of its utility plant assets?

A. The Company's response to DPU 9-2 indicates that the Company has recently transitioned to PowerTax to track such information and is currently investigating how and if the PowerTax software may be utilized to calculate the amortization of the excess ADIT using the ARAM.

Q. Is PowerTax the software that is being used by other utilities to calculate the amortization of excess ADIT under the ARAM?

A. Yes. It appears that many utilities, particularly larger utilities, are using the PowerTax software to calculate the amortization of excess ADIT under the ARAM, as well as to track the tax depreciation on utility plant assets for other purposes.

Q. Please explain your current understanding of the average rate assumption method that is specified in the Tax Act for compliance with normalization requirements on the "protected" excess ADIT.

A. The ARAM is the method under which the “protected” excess in the reserve for deferred taxes is reduced over the remaining lives of the property as recorded in the utility’s regulated books of account which gave rise to the reserve for deferred taxes. Under this method, if timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying (1) the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question (Tax Act §13001(d)(3)(B)(i)) by (2) the amount of the timing differences that reverse during the period. (Tax Act §13001(d)(3)(B)(ii))

The reversal of timing differences generally occurs when the amount of the tax depreciation taken on the asset is less than the amount of the regulatory (book) depreciation taken on the asset. To ensure that the deferred tax reserve, including the excess tax reserve, is reduced to zero at the end of the regulatory life of the asset that generated the reserve, the amount of the timing difference which reverses during a tax year is multiplied by the ratio of (1) the aggregate deferred taxes as of the beginning of the period in question to (2) the aggregate timing differences for the property as of the beginning of the period in question.

Q. Should SWRI be required to present an ARAM calculation in the current rate case?

A. Yes. Ideally, SWRI should present a calculation of the "protected" excess ADIT amortization at least for 2018 and 2019 using the ARAM. Such calculation, subject to review, should then be used for the rate year impact of the "protected" excess ADIT.

Q. Does the TCJA provide for an alternative method of amortizing the "protected" excess ADIT if sufficient information is not available to utilize the ARAM?

A. Yes. If sufficient information to utilize the ARAM is not available, the TCJA provides that the amortization period for the "protected" excess ADIT should be based on an alternative normalization method, such as the Reverse South Georgia Method. If the alternative method is to be used, a calculation would be needed of the composite depreciation rate (estimate of the remaining life of the utility property) excluding the component for negative net salvage.

Q. What amortization period have you reflected for the Company's "protected" excess ADIT?

A. As shown on Exhibit RCS-2, Schedule C-11, page 1, line 19, I have used 50 years as a placeholder. As noted above, this should be replaced by accurate ARAM-based information if Suez Water is able to provide it during the rate case.

<u>Calculation of TCJA-Related Regulatory Liability Amortization Adjustment to Rate Year Income Tax Expense</u>

Q. What has SWRI proposed in its Application for excess ADIT amortization?

A. SWRI has proposed an amortization of what it refers to as its "Regulatory Liability TCJA" of $33,604 as a reduction to income tax expense. This is shown on Exhibit 3 (Gil), Schedule 21, on line 12, in the Company's Application and is reproduced on Exhibit RCS-2, Schedule C-11, page 1, on lines 19-23, columns A through C.

Q. How did SWRI derive that amount?

A. Per details supporting the Company's Exhibit 4 (Cagle), Schedule 5C, the Company started with its Regulatory Liability amount for excess ADIT at December 31, 2017 of $1,550,538 and added some estimated amounts of 2018 federal income tax savings for the months of January through September of $129,640 to derive an estimated Regulatory Liability amount of $1,680,178 as of September 30, 2018, which the Company is proposing to amortize over 50 years.[7] Thus, the Company made no distinction in the amortization periods to be applied for "protected" and "unprotected" excess ADIT, or for the 2018 federal income tax savings through

[7] $1,680,178 divided by 50 years equals the $33,604 amount of reduction to income tax expense shown on Suez Water Exhibit 3 (Gil), Schedule 21, line 12.

September 30. As summarized in the following table, the Company has effectively applied a 50 year amortization period for all TCJA-related regulatory liability items:

Company Proposed Reduction to Rate Year Income Tax Expense for TCJA Regulatory Liability			
Component	Company Proposed Regualory Liabiltiy Amount	Company Proposed Amortization Period in Years	Company Proposed Reduction to Rate Year Income Tax Expense
Excess ADIT (Regulatory Liability) at December 31, 2017	$ (1,550,538)	50	$ (31,011)
Company estimated 2018 FIT Savings through September 2018	$ (129,640)	50	$ (2,593)
Total Company proposed Regulatory Liability at 9/30/2018	$ (1,680,178)		$ (33,604)
Source: SUEZ Water Exhibit 4 (Cagle), Schedule 5C			

Q. Do you agree with the Company's proposed reduction to federal income tax expense of $33,604 based on a 50-year amortization for all TCJA related items that are being accumulated as Regulatory Liabilities?

A. No. As described above, the Company should provide in the current rate case its ARAM-based amortizations for 2018 and 2019 of the "protected" excess ADIT, which it appears should consist only of the excess ADIT related to the Deferred FIT-MACRS item that Suez Water recorded in account 28203. If an alternative method needs to be used because Suez Water cannot produce ARAM calculations, the remaining depreciable life of the Company's utility property (e.g., based on a composite depreciation rate excluding the component for negative net salvage/cost of removal) could potentially be used.[8]

[8] The alternative method is sometimes referred to by regulators as the "Reverse South Georgia Method."

The remainder of the excess ADIT should be considered to be "non-protected" and should be amortized over a relatively short period to be determined by the Commission. As shown on Exhibit RCS-2, Schedule C-11, page 1, in part because of the relatively small amount of "non-protected" excess ADIT, I have used a three-year amortization period.

I have also used a three-year amortization period for the portion of the estimated TCJA Regulatory Liability related to federal income tax savings from January 1, 2018 through the September 30, 2018 (October 1, 2018) effective date of new rates. As noted above, the three-year amortization period approximates the rate case filing cycle; the same period is being applied to the amortization of the Company's rate case expense.

Q. What amount of annual TCJA related Regulatory Liability amortization for the rate year have you calculated?

A. As shown on Exhibit RCS-2, Schedule C-11, page 1, I have calculated annual TCJA related Regulatory Liability amortization of $98,867, which reduces rate year income taxes by that amount. Put another way, this amortization of the components of the TCJA related Regulatory Liability reduces rate year federal income tax expense by $98,867, which is $65,263 more of a reduction than the $33,604 reduction proposed by Suez Water.

V. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Q. Is the Company proposing to establish a surcharge for the purpose of recovering the costs associated with the replacement and rehabilitation of its transmission and distribution ("T&D") system, which includes mains, services, hydrants, valves and meters?

A. Yes. As discussed in the direct testimony of Company witness Gary Prettyman, the Company is proposing to establish a Distribution System Improvement Charge ("DSIC") for the purpose of recovering the costs associated with the replacement and rehabilitation of its transmission and distribution ("T&D") system.

Q. Please explain what a DSIC is?

A. A DSIC is a mechanism which allows for the recovery of non-revenue producing investments made to replace aging utility infrastructure between base rate case proceedings. As discussed on page 2 of Mr. Prettyman's testimony, with the establishment of a DSIC, utilities can recover these types of investments on a timelier basis than would be the case with a rate case filing, as well as avoiding the costs of a rate case.

Q. Has SWRI identified a timetable for replacing its aging infrastructure?

A. Yes. On page 3 of his testimony, Mr. Prettyman stated that the Company had 154 miles of mains at the end of 2017, of which 0.16 miles were replaced during 2017. Mr. Prettyman states that based on the 2017 level of activity, it would take SWRI approximately 962 years to replace its entire system and that a DSIC would allow the Company to implement a more aggressive infrastructure replacement program.

Q. Has SWRI identified specific areas of concern within its service territory?

A. Yes. On page 3 of his testimony, Mr. Prettyman identified the following three areas of concern within its service territory: (1) the River Street, Pond Street and Winchester Street areas of South Kingston; (2) the Ocean Road and Boston Neck Road areas of Narragansett; and (3) the Bonnet Shores area of Narragansett. In each of these service areas, Mr. Prettyman states that the mains are constructed of either asbestos cement and/or galvanized iron which frequently have breaks.

Q. Please discuss the DSIC that SWRI is requesting.

A. On page 5 of his testimony, Mr. Prettyman states that the DSIC being requested should reflect qualified non-revenue producing additions that either replace or rehabilitate its infrastructure, and that qualified additions include: mains, main cleaning and lining, services, hydrants, valves, short mains and valves, meters, dead-end looping, and relocation due to government requirements.

Q. How does SWRI propose to recover the DSIC?

A. SWRI proposes to apply a surcharge to all of its customers bills that is equal to the percentage that results from dividing the DSIC revenue requirement by SWRI's projected revenues for the prospective six months. In addition, the DSIC surcharge would be applied on a "bills rendered" basis and the Commission would have 30 days to review its DSIC application. Furthermore, SWRI would include a reconciliation of the over/(under) recovery of the DSIC surcharge as part of its subsequent six month filing and an earnings test would be performed after the first year of DSIC surcharges then every six months thereafter. SWRI proposes to zero out the DSIC surcharge at the time of its next base rate case.

Q. Has SWRI identified any customer benefits associated with implementing a DSIC?

A. Yes. On page 4 of his testimony, Mr. Prettyman states that implementing a DSIC would benefit its customers by: (1) reducing main breaks and associated overtime; (2) improving water quality and fire flows; (3) lengthening time between rate cases which reduces rate case expense; and (4) smaller rate increases over time thus minimizing rate shock. In addition, the foregoing items would reduce operating expenses over time.

Q. Has the Company quantified or reflected cost savings related to those claimed benefits?

A. It appears not.

Q. Does SWRI state whether its proposed DSIC has any customer protections?

A. Yes. On page 5 of his testimony, Mr. Prettyman states the following:

> Commissions have the ability to review the projects to ensure they are appropriate and there is generally a cap on the amount of increases that can happen between rate cases. DSICs in other states also require that an earnings analysis be performed to determine if a company is over earning; if a company is over earning, then the surcharge would stop until such time as the company is in an under earning position. Some states also perform an annual audit of the program to review the actual projects implemented by the company.

Q. Is the Company proposing a cap on the DSIC surcharge?

A. Yes. The Company is proposing a 7.5 percent cap on the proposed DSIC surcharge.

Q. Should a cap be imposed on the DSIC surcharge?

A. Yes, an annual cap of 2.5 percent and a cumulative cap of 7.5 percent should be imposed.

Q. Has SWRI stated what would be included in the revenue requirement of the proposed DSIC?

A. Yes. The DSIC's rate of return would be based on what was approved in the Company's last rate case and the DSIC rate base would include accumulated depreciation and deferred federal income tax ("DFIT") on only qualified additions plus depreciation expense. In addition, revenue taxes would be grossed-up and the revenue requirement would be on a pre-tax basis.

Q. Do you agree with the establishment of the DSIC as proposed by SWRI?

A. Not as proposed by SWRI. The Division is not opposed to having a DSIC for SWRI, but the one proposed by SWRI is not being endorsed because it does not provide for adequate review, is unbalanced in favor of investors and against ratepayers, and lacks adequate customer protections.

Q. What modifications to the SWRI proposed DSIC are you presenting on behalf of the Division?

A. The following modifications should be made to the SWRI-proposed DSIC:

1) DSIC Eligible plant should be limited to replacement of non-revenue producing transmission and distribution mains and services.

2) How Suez Water is financing its prospective replacement of utility infrastructure, such as old, leak-prone transmission and distribution mains and services, between rate cases should be carefully monitored. For example, if such infrastructure replacement investment can be financed with short-term debt or bonds between rate cases, ratepayers should not be charged with an equity return. Additionally, since there would be virtually no risk of recovery for the DSIC-includable projects, the return on equity applicable for the surcharge should be reduced to reflect the lower risk.

3) Relationship to Base Rate Cases - At no point shall there be (i) utility plant assets that are simultaneously included in base rates and a DSIC Rate Component or (ii) a base rate that provides or will provide the Company with recovery of revenues associated with the revenue requirement on investments for which an DSIC Rate Component provides or will provide simultaneous recovery (and vice versa). Calculations of utility plant in service and revenue requirements in each base rate case and annual DSIC filing will include appropriate adjustments to ensure these outcomes do not occur.

4) The Company shall not have a base rate case and a DSIC filing simultaneously pending before the Commission.

5) Annual Cap of 2.5 percent - In each annual DSIC filing or amendment to an DSIC filing, the DSIC Rate Component proposed to be collected in the succeeding annual period (inclusive of the impact of any reconciliation scheduled for implementation during that period) will be limited to an amount

that does not exceed 2.5 percent of the revenue requirement authorized in the most recent base rate case.

6) Cumulative Cap of 7.5 percent - In each annual DSIC filing or amendment to an DSIC filing, the DSIC Rate Component proposed to be collected in the succeeding annual period (inclusive of the impact of any reconciliation scheduled for implementation during that period) will be limited to an amount that, when combined with the percentage increase(s) implemented through previous DSIC filings since the most recent rate case, does not exceed 7.5 percent of the revenue requirement authorized in the most recent base rate case.

7) Reconciliation of estimated amounts used in DSIC filings - estimated amounts for plant additions used in DSIC applications shall be trued-up to actual amounts in the subsequent DSIC filing.

8) Earnings Test - The Company will not be permitted to implement a DSIC Rate Component in the following circumstances:

(a) after a DSIC investment base reset to zero following a base rate case order;

(b) if an annual DSIC Rate Component is already in place, to increase the existing DSIC Rate Component with a subsequent calendar year's incremental projected investment in DSIC Facilities; or

(c) if the Company's achieved return on average equity investment for regulatory accounting purposes and measured on a calendar year basis, exceeds the authorized return on common equity set in the Company's most recent base rate case.

If one of these situations occurs, then the Company will still make its annual DSIC filing, but only for purposes of maintaining the existing DSIC Rate Component (if any) and for addressing any needed reconciliations of costs and revenues from previous years.

9) The DSIC rate base will reflect deductions for an amount equivalent to the annual depreciation expenses imbedded in the base rates for the types of plant that are being addressed by the DSIC capital investment, such that there will be no DSIC adjustment for a year until and unless the new capital spending for non-revenue producing transmission and distribution mains and services exceeds the amount of annual depreciation allowed for mains and services in the Company's most recent rate case.

10) The DSIC will terminate after five years or until the utility has its base rates reset in a base rate case, whichever occurs sooner;

11) The DSIC rate base will reflect a reduction for the provision for the accelerated tax depreciation on the DSIC-includable plant additions, i.e., the DSIC rate base will be reduced to reflect the ADIT amounts on DSIC includable plant.

12) As recognition of the reduction in risk related to regulatory lag and for recovery of the revenue requirement associated with capital investment in replacing mains and services between rate cases, the cost of capital for the DSIC should be lower than the cost of capital used in the general rate case; and

13) The Division and Commission should have at least 120 days to review the DSIC filing before rates are adjusted; and

14) Other reporting requirements, such as reporting on improvements in the quality of service, reductions to leaks, and reductions to lost and unaccounted for water, etc. should also be required.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)

Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
Cause No. 43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)

2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015 -0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014	PTE Pipeline LLC (Regulatory Commission of Alaska)
P-15-020	Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P (Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
Docket No. 4618	Providence Water Supply Board (Rhode Island PUC)
Docket No. 46238	Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC)
U-16-066	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Case No. 2016-00370	Kentucky Utilities Company (Kentucky PSC)
Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142*	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322*	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034*	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)

Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
Formal Case No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No .2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)

* Testimony filed, examination not completed
** Issues stipulated
*** Company withdrew case
^ Testimony filed, case withdrawn after proposed decision issued
^^ Issues stipulated before testimony was filed

Suez Water Rhode Island, Inc.
Docket No. 4800
Exhibit RCS-2
Revenue Requirement and Adjustment Schedules
Accompanying the Direct Testimony of Ralph Smith

Suez Water Rhode Island, Inc.
Calculation of Revenue Deficiency (Sufficiency)

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule A
Docket No. 4800
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Line No.	Description	Reference	Per Company (A)	Per Division (B)	Difference (C)
1	Adjusted rate base	B	$ 20,542,519	$ 20,241,177	$ (301,342)
2	Rate of return	D	7.82%	6.98%	
3	Net operating income required		$ 1,606,425	$ 1,412,834	$ (193,591)
4	Adjusted net operating income	C	$ 810,371	$ 1,074,714	$ 264,343
5	Net operating income deficiency		$ 796,054	$ 338,120	$ (457,934)
6	Gross revenue conversion factor	A-1	1.287424	1.287424	
7	Revenue deficiency		$ 1,024,859	$ 435,303	$ (589,556)
8	Rounding		$ (3)		
9	Revenue deficiency		$ 1,024,856	$ 435,303	$ (589,553)

Notes and Source

Line No.	Description	Reference	Per Company (A)	Per Division (B)
10	Operating Revenue at Current Rates	C	$ 4,813,887	$ 4,813,887
11	Percentage Increase	L9 / L10	21.29%	9.04%

Suez Water Rhode Island, Inc.
Revenue Requirement Reconciliation

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule A
Docket No. 4800
Page 2 of 2

Line No.	Description	Schedule Reference	Component	Division Adjustments (A)	Division Multiplier (B)	Division Revenue Requirement Amount (C)
		D	ROR Difference		-0.8400%	
	Rate Base	A-1	GRCF		x 1.287424	
1	Rate Base per Suez's Filing	B		$ 20,542,519	-1.081%	$ (222,154)
		D	Rate of Return		6.980%	
	Effect of Division Adjustments to Rate Base	A-1	GRCF		x 1.287424	
2	Unamortized Rate Case Expense	B-1		$ (87,383)	8.99%	$ (7,852)
3	Cash Working Capital	B-2		$ (213,959)	8.99%	$ (19,227)
4	Total Division Rate Base Adjustments			$ (301,342)		
5	**Division Adjusted Original Cost Rate Base**	B		$ 20,241,177		
	Net Operating Income		Pre-Tax	Net Operating	Division	
			Operating Income	Income Amount	GRCF	
	Effect of Division Adjustments on NOI		Amount	Sch C.1	Sch. A-1	
6	Depreciation Expense	C-1	$ 53,231	$ 42,053	1.287424	$ (54,140)
7	Wages and Salaries Expense	C-2	$ 48,247	$ 38,115	1.287424	$ (49,070)
8	Incentive Compensation Expense	C-3	$ 35,337	$ 27,916	1.287424	$ (35,940)
9	Payroll Tax Expense	C-4	$ 6,394	$ 5,051	1.287424	$ (6,503)
10	Property Tax Expense	C-5	$ 11,082	$ 8,755	1.287424	$ (11,272)
11	Transportation & Vehicle Lease Expense	C-6	$ 13,592	$ 10,738	1.287424	$ (13,824)
12	Management & Services Expense	C-7	$ 64,736	$ 51,141	1.287424	$ (65,841)
13	Chemical Expense	C-8	$ (1,113)	$ (879)	1.287424	$ 1,131
14	Power Expense	C-9	$ 22,199	$ 17,537	1.287424	$ (22,578)
15	Interest Synchronization	C-10	$ -	$ (1,348)	1.287424	$ 1,735
16	Federal Income Tax Expense	C-11	$ -	$ 65,263	1.287424	$ (84,022)
17	Total Division Adjustments to Operating Income	C.1	$ 253,706	$ 264,343		
18	Net Operating Income per Company Filing	C		$ 810,371		
19	**Division Adjusted Net Operating Income**	C		$ 1,074,714		
	Gross Revenue Conversion Factor Difference:					
20	Per Division	A-1			1.287424	
21	Per Company	A-1			1.287424	
22	Difference				0.000000	
23	Company Adjusted NOI Deficiency	A			$ 796,054	
24	GRCF Difference					$ -
25	DIVISION REVENUE REQUIREMENT ADJUSTMENTS ABOVE					$ (589,557)
26	Company Requested Base Rate Revenues	A				$ 1,024,859
27	Reconciled Revenue Requirement					$ 435,302
28	Revenue Requirement Calculated on Schedule A	A				$ 435,303
29	Difference from Above					$ (1)

Notes and Source

Pre-tax return computed using Gross Revenue Conversion Factor

Suez Water Rhode Island, Inc.
Gross Revenue Conversion Factor

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule A-1
Docket No. 4800
Page 1 of 1

Line No.	Description		Company Proposed Amounts	Division Proposed	Difference
			(A)	(B)	(C) = (B) - (A)
1	Gross Revenue		1.000000	1.000000	-
	Rate Applicable to O&M Expenses				
2	PSC Assessment		0.43%	0.43%	-
3	Gross Receipts Tax		1.25%	1.25%	-
			1.68%	1.68%	-
4	Taxable Income		98.32%	98.32%	-
5	Federal Income Taxes	21%	20.65%	20.65%	-
6	Net of Tax		77.67%	77.67%	-
7	Gross Revenue Conversion Factor		1.287424	1.287424	-

Notes and Source
Col. A: Response to DPU 2-3

Components of Revenue Requirement Increase

Line No.	Description	Percent	Amount
		(D)	(E)
8	Net Income	77.67%	$ 338,119
9	PSC Assessment	0.43%	$ 1,861
10	Gross Receipts Tax	1.25%	$ 5,441
11	Federal Income Taxes	20.65%	$ 89,881
12	Total Revenue Increase	100.00%	$ 435,303
13	Total Revenue Increase per Schedule A		$ 435,303

Suez Water Rhode Island, Inc.
Adjusted Rate Base

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule B
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Page 1 of 1

Line No.	Description	Company Proposed (A)	Division Adjustments (B)	Division Proposed (C)
1	Utility Plant in Service	$ 36,073,465	$ -	$ 36,073,465
2	Accumulated Depreciation	$ (8,362,574)	$ -	$ (8,362,574)
3	Net Utility Plant in Service	$ 27,710,891	$ -	$ 27,710,891
4	Materials and Supplies	$ 202,236	$ -	$ 202,236
5	Cash Working Capital (CWC)	$ 307,171	$ (213,959)	$ 93,212
6	Def'd Tank Painting (net of Def'd Tax)	$ 58,682	$ -	$ 58,682
7	Def'd Rate Case (net of Def'd Tax)	$ 87,383	$ (87,383)	$ -
8	Total Additions to Rate Base	$ 655,472	$ (301,342)	$ 354,130
9	CIAC	$ (3,560,845)	$ -	$ (3,560,845)
10	Def'd Income Tax	$ (1,866,387)	$ -	$ (1,866,387)
11	Regulatory Liability - Tax rate change	$ (1,663,377)	$ -	$ (1,663,377)
12	Unamortized ITC	$ (66,926)	$ -	$ (66,926)
13	Unfunded FAS 106 (net of Def'd Tax)	$ (666,309)	$ -	$ (666,309)
14	Total Deductions from Rate Base	$ (7,823,844)	$ -	$ (7,823,844)
15	**Total Rate Base**	$ 20,542,519	$ (301,342)	$ 20,241,177

Notes and Source

Col.A: Exhibit 4 (Gil), Schedule 1, page 1 of 5 from the Company's filing

Suez Water Rhode Island, Inc.
Summary of Adjustments to Rate Base

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule B.1
Docket No. 4800
Page 1 of 1

Line No.	Description	Division Adjustments	Unamortized Rate Case Expense B-1	Cash Working Capital B-2
1	Utility Plant in Service	$ -		
2	Accumulated Depreciation	$ -		
3	Net Utility Plant in Service	$ -	$ -	$ -
4	Materials and Supplies	$ -		
5	Cash Working Capital (CWC)	$ (213,959)		$ (213,959)
6	Def'd Tank Painting (net of Def'd Tax)	$ -		
7	Def'd Rate Case (net of Def'd Tax)	$ (87,383)	$ (87,383)	
8		$ (301,342)	$ (87,383)	$ (213,959)
9	CIAC			
10	Def'd Income Tax	$ -		
11	Regulatory Liability - Tax rate change	$ -		
12	Unamortized ITC	$ -		
13	Unfunded FAS 106 (net of Def'd Tax)	$ -		
14		$ -	$ -	$ -
15	**Total Rate Base**	$ (301,342)	$ (87,383)	$ (213,959)

Suez Water Rhode Island, Inc.
Adjusted Net Operating Income

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule C
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Line No.	Description	Per Company (A)	Division Adjustments (B)	Division Proposed (C)	Division Revenue Requirement Change (D)	Revenue Requirement Impact (E)
1	Operating Revenues	$ 4,813,887	$ -	$ 4,813,887	$ 435,303	$ 5,249,190
	Operating Expenses:					
2	Operating and Maintenance Expenses	$ 2,510,506	$ (182,999)	$ 2,327,507	$ 1,861	$ 2,329,368
3	Depreciation and Amortization	$ 905,502	$ (53,231)	$ 852,271		$ 852,271
4	Taxes Other Than Income	$ 536,842	$ (17,476)	$ 519,366	$ 5,441	$ 524,807
5	Federal Income Taxes	$ 50,666	$ (10,637)	$ 40,029	$ 89,881	$ 129,910
6	Total Operating Expenses	$ 4,003,516	$ (264,343)	$ 3,739,173	$ 97,184	$ 3,836,356
7	**Operating Income**	**$ 810,371**	**$ 264,343**	**$ 1,074,714**	**$ 338,119**	**$ 1,412,834**
8	Rate Base	$ 20,542,519	$ (301,342)	$ 20,241,177		$ 20,241,177
9	Earned Rate of Return	3.94%		5.31%		6.98%

Notes and Source
Col.A: Exhibit 1 (Gil), Schedule 1 from the Company's filing

Suez Water Rhode Island, Inc.
Summary of Net Operating Income Adjustments

Rate Year Ending September 30, 2019

Line No.	Description	Division Adjustments	Depreciation Expense C-1	Wages and Salaries C-2	Incentive Compensation Expense C-3	Payroll Tax Expense C-4	Property Tax Expense C-5	Transportation & Vehicle Expense C-6	Management & Services Expense C-7	Chemical Expense C-8	Power Expense C-9
1	Operating Revenues	$ -									
	Operating Expenses:										
2	Operating and Maintenance Expenses	$ (182,999)		$ (48,247)	$ (35,337)			$ (13,592)	$ (64,736)	$ 1,113	$ (22,199)
3	Depreciation and Amortization	$ (53,231)	$ (53,231)								
4	Taxes Other Than Income	$ (17,476)				$ (6,394)	$ (11,082)				
5	Pre-Tax Operating Expenses	$ (253,706)	$ (53,231)	$ (48,247)	$ (35,337)	$ (6,394)	$ (11,082)	$ (13,592)	$ (64,736)	$ 1,113	$ (22,199)
6	Pre-Tax Operating Income	$ 253,706	$ 53,231	$ 48,247	$ 35,337	$ 6,394	$ 11,082	$ 13,592	$ 64,736	$ (1,113)	$ 22,199
7	Federal Income Taxes	$ (10,637)	$ 11,178	$ 10,132	$ 7,421	$ 1,343	$ 2,327	$ 2,854	$ 13,595	$ (234)	$ 4,662
8	Total Operating Expenses	$ (264,343)	$ (42,053)	$ (38,115)	$ (27,916)	$ (5,051)	$ (8,755)	$ (10,738)	$ (51,141)	$ 879	$ (17,537)
9	**Operating Income**	$ 264,343	$ 42,053	$ 38,115	$ 27,916	$ 5,051	$ 8,755	$ 10,738	$ 51,141	$ (879)	$ 17,537

Notes and Source
Line 15: Federal Income Tax Rate 21.00%

Suez Water Rhode Island, Inc.
Summary of Net Operating Income Adjustments

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule C.1
Docket No. 4800
Page 2 of 2

Line No.	Description	Interest Synchronization C-10	Federal Income Tax Expense C-11
1	Operating Revenues		
	Operating Expenses:		
2	Operating and Maintenance Expenses		
3	Depreciation and Amortization		
4	Taxes Other Than Income		
5	Pre-Tax Operating Expenses	$ -	$ -
6	Pre-Tax Operating Income	$ -	$ -
7	Federal Income Taxes	$ 1,348	$ (65,263)
8	Total Operating Expenses	$ 1,348	$ (65,263)
9	**Operating Income**	$ (1,348)	$ 65,263

Notes and Source
Line 15: Federal Income Tax Rate 21.00%

Suez Water Rhode Island, Inc.
Capital Structure and Cost Rates

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule D
Docket No. 4800
Page 1 of 1

Line No.	Description		Amount	Percent	Cost Rate	Weighted Cost
			(A)	(B)	(C)	(D)
	Per Company					
1	Long Term Debt	$	943,645,843	45.81%	4.65%	2.13%
2	Common Equity	$	1,116,396,205	54.19%	10.50%	5.69%
3	Total Capital Structure	$	2,060,042,048	100.00%		7.82%
	Per Division					
4	Long-Term Debt	$	943,645,843	45.57%	4.65%	2.12%
5	Short-Term Debt	$	10,847,000	0.52%	2.65%	0.01%
6	Common Equity	$	1,116,396,205	53.91%	**9.00%**	4.85%
7	Total Capital Structure	$	2,070,889,048	100.00%		6.98%
8	Difference					-0.840%
9	Weighted Cost of Debt					2.13%

Notes and Source
Lines 1-3: Exhibit HW-1, Schedule 1 from the Company's filing
Lines 4-7: Cost rates and Return on Equity as recommended by Division witness Matt Kahal

Suez Water Rhode Island, Inc.
Unamortized Rate Case Expense

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule B-1
Docket No. 4800
Page 1 of 1

Line No.	Description	Amount (A)	Reference
1	Adjustment to Remove Unamortized Rate Case Expense	$ (87,383)	A

Notes and Source
A: Amount from Exhibit, Schedule 1, page 1 from SWRI's filing

Suez Water Rhode Island, Inc.
Cash Working Capital

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule B-2
Docket No. 4800
Page 1 of 1

Line No.	Description	Reference	Expense Amount (A)	Cash Working Capital 12.5% (B)
1	Cash Working Capital Per Company	Exh. 4 (Gil), Sch. 1		$ 307,171
2	Exclude Tank Painting Amortization	DPU 9-31	$ (19,812)	$ (2,477)
3	Wages and Salaries Expense	Sch. C-2	$ (48,247)	$ (6,031)
4	Incentive Compensation Expense	Sch. C-3	$ (35,337)	$ (4,417)
5	Payroll Tax Expense	Sch. C-4	$ (6,394)	$ (799)
6	Property Tax Expense	Sch. C-5	$ (11,082)	$ (1,385)
7	Transportation & Vehicle Lease Expense	Sch. C-6	$ (13,592)	$ (1,699)
8	Management & Services Expense	Sch. C-7	$ (64,736)	$ (8,092)
9	Chemical Expense	Sch. C-8	$ 1,113	$ 139
10	Power Expense	Sch. C-9	$ (22,199)	$ (2,775)
11	Adjustment to Cash Working Capital			$ (27,536)
12	Adjusted Cash Working Capital Per Division			$ 279,635
13	Adjustment to Remove 2/3 of CWC to Reflect Change from Quarterly to Monthly Billing			$ (186,423)
14	Cash Working Capital Per Division			$ 93,212
15	Total Adjustment to Cash Working Capital			$ (213,959)

Notes and Source:
SWRI's cash working capital calculated using the 1/8th formula

Suez Water Rhode Island, Inc.
Depreciation Expense

Rate Year Ending September 30, 2019

			Per Company				Rate Year Average 13m		Rate Year 12m			Per Division			
Line No.	Plant Account	Account Description	Depr Rate Actual	Depr Rate Proposed	Plant In Service 9/30/2017	Accum Deprec 9/30/2017	Plant In Service	Accumulated Depreciation	Depreciation Expense	Derived Depreciation Rate	Difference	Depr Rate Recommended	Plant In Service	Depreciation Expense	Difference
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = G / E	(I) = H - B	(J)	(K)	(L) = J x K	(M) = L - G
1	301	301-Intangible Plant-Organizat			$ 51,107	$ -	$ 51,107	$ -	$ -	0.00%	-		$ 51,107	$ -	$ -
2	303	303-Intangible Plant-Miscellan		8.63%	$ 231,444	$ -	$ 93,794	$ (133,602)	$ 8,094	8.63%	-	8.63%	$ 93,794	$ 8,094	$ -
3	310	310-Source Of Supply-Land And			$ 27,717	$ -	$ 27,717	$ -	$ -	0.00%	-		$ 27,717	$ -	$ -
4	311	311-Source Of Supply-Stuctures	2.00%	2.20%	$ 105,260	$ 23,707	$ 105,260	$ 26,970	$ 2,316	2.20%	-	2.20%	$ 105,260	$ 2,316	$ -
5	314	314-Source Of Supply-Wells And	2.00%	3.98%	$ 567,394	$ 136,242	$ 567,394	$ 158,881	$ 22,582	3.98%	-	3.98%	$ 567,394	$ 22,582	$ -
6	316	316-Source Of Supply-Supply Ma	1.25%	2.87%	$ 58,771	$ 17,420	$ 58,771	$ 18,998	$ 1,687	2.87%	-	2.87%	$ 58,771	$ 1,687	$ -
7	317	317-Source Of Supply-Other Wat		1.94%	$ 1,601	$ (192)	$ 1,601	$ (177)	$ 31	1.94%	-	1.94%	$ 1,601	$ 31	$ -
8	320	320-Pumping Plant-Land And Lan			$ 5,601	$ -	$ 5,601	$ -	$ -	0.00%	-		$ 5,601	$ -	$ -
9	321	321-Pumping Plant-Stuctures An	2.00%	2.20%	$ 679,636	$ 194,569	$ 708,032	$ 197,474	$ 15,530	2.19%	-0.01%	2.20%	$ 708,032	$ 15,530	$ -
10	325	325-Pumping Plant-Electric Pum	4.00%	1.90%	$ 1,611,761	$ 1,191,318	$ 1,600,025	$ 1,123,831	$ 30,337	1.90%	-	1.73%	$ 1,600,025	$ 27,680	$ (2,656)
11	328	328-Pumping Plant-Other Pumpin	4.00%	2.05%	$ 108,877	$ 64,900	$ 101,513	$ 62,661	$ 2,081	2.05%	-	2.05%	$ 101,513	$ 2,081	$ -
12	331	331-Water Treat Plant-Stucture	2.00%	2.30%	$ 18,475	$ 11,652	$ 9,437	$ 2,928	$ 217	2.30%	-	2.30%	$ 9,437	$ 217	$ -
13	332	332-Water Treat Plant-Water Tr	5.00%	2.08%	$ 543,625	$ 370,469	$ 492,038	$ 340,028	$ 10,227	2.08%	-	2.08%	$ 492,038	$ 10,227	$ -
14	340	340-T&D Plant-Land And Land Ri			$ 1,862	$ -	$ 1,862	$ -	$ -	0.00%	-		$ 1,862	$ -	$ -
15	341	341-T&D Plant-Stuctures And Im	3.00%	1.66%	$ 139,985	$ 43,648	$ 139,985	$ 49,009	$ 2,324	1.66%	-	1.66%	$ 139,985	$ 2,324	$ -
16	342	342-T&D Plant-Distr Reservoirs	1.33%	2.93%	$ 4,323,023	$ 294,599	$ 7,545,523	$ 394,559	$ 221,084	2.93%	-	2.93%	$ 7,545,523	$ 221,084	$ -
17	343	343-T&D Plant-Transmission And	1.25%	1.29%	$ 12,986,532	$ 3,416,833	$ 13,577,008	$ 3,403,519	$ 173,878	1.28%	-0.01%	1.23%	$ 13,577,008	$ 166,997	$ (6,880)
18	345	345-T&D Plant-Services	2.00%	1.76%	$ 4,019,094	$ 1,273,515	$ 4,281,555	$ 1,385,386	$ 75,235	1.76%	-	1.76%	$ 4,281,555	$ 75,235	$ -
19	346	346-T&D Plant-Meters	3.00%	2.56%	$ 3,017,840	$ 932,659	$ 3,493,702	$ 1,030,909	$ 89,036	2.55%	-0.01%	2.56%	$ 3,493,702	$ 89,036	$ -
20	348	348-T&D Plant-Hydrants	2.00%	1.73%	$ 1,094,287	$ 435,787	$ 1,131,653	$ 465,906	$ 19,561	1.73%	-	1.73%	$ 1,131,653	$ 19,561	$ -
21	390	390-General Plant-Stuctures An	5.00%	1.45%	$ 237,438	$ 99,197	$ 193,272	$ 66,280	$ 2,802	1.45%	-	1.45%	$ 193,272	$ 2,802	$ -
22	390L	390-General Plant-Leasehold improvements	12.50%	12.50%	$ -	$ -	$ 210,000	$ 31,875	$ 26,250	12.50%	-	12.50%	$ 210,000	$ 26,250	$ -
23	391	391-General Plant-Office Furni	10.00%	12.58%	$ 62,632	$ (138,061)	$ 61,084	$ (170,895)	$ 7,614	12.46%	-0.12%	12.58%	$ 61,084	$ 7,614	$ -
24	391H	391-General Plant-Computer Hardware	10.00%	20.02%	$ 103,713	$ 48,180	$ 103,713	$ 68,933	$ 20,763	20.02%	-	20.02%	$ 103,713	$ 20,763	$ -
25	391S	391-General Plant-Computer Software	10.00%	25.66%	$ 304,063	$ 12,553	$ 417,991	$ 96,937	$ 106,676	25.52%	-0.14%	25.66%	$ 417,991	$ 106,676	$ -
26	391CB	391-General Plant-Computer Soft Lighthouse	12.50%	12.50%	$ 552,856	$ 407,511	$ 552,856	$ 511,171	$ 69,107	12.50%	-	12.50%	$ 552,856	$ 69,107	$ -
27	392	392-General Plant-Transportati	2.50%	12.87%	$ 3,451	$ 525	$ 3,451	$ 833	$ 444	12.87%	-	12.87%	$ 3,451	$ 444	$ -
28	394	394-General Plant-Tools, Shop	10.00%	2.33%	$ 89,648	$ 67,167	$ 86,792	$ 59,878	$ 2,017	2.32%	-0.01%	2.33%	$ 86,792	$ 2,017	$ -
29	396	396-General Plant-Power Operat	10.00%	4.33%	$ 15,685	$ 12,287	$ 15,685	$ 14,195	$ 679	4.33%	-	4.33%	$ 15,685	$ 679	$ -
30	397	397-General Plant-Communicatio	5.00%	10.05%	$ 330,683	$ 81,104	$ 355,365	$ 114,954	$ 35,566	10.01%	-0.04%	10.05%	$ 355,365	$ 35,566	$ -
31	398	398-General Plant-Miscellaneou	2.00%	5.80%	$ 79,677	$ 18,076	$ 79,677	$ 21,980	$ 4,621	5.80%	-	5.80%	$ 79,677	$ 4,621	$ -
32		Accumulated Amortization of CIAC				$ (915,177)	$ -	$ (980,847)	$ (45,258)				$ -	$ (45,258)	$ -
33		Total			$ 31,373,738	$ 8,100,486	$ 36,073,465	$ 8,362,574	$ 905,502				$ 36,073,465	$ 895,965	$ (9,537)
34		Adjustment to Plant Account 391CB - see page 2													$ (43,694)
35		Total Division Adjustment to Depreciation Expense													$ (53,231)

Notes and Source:
Columns A-G: Exhibit 4, Schedule 3 from the Company's filing
Column J: Division witness Roxie McCullar

Calculated composite depreciation rate	Annual Depreciation / Plant	2.51%	2.48%

Suez Water Rhode Island, Inc.
Depreciation Expense - Customer Information System

Rate Year Ending September 30, 2019

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Line No.	Description	Amount (A)	Reference
1	Remaining Net Book Value at 9/30/2018 (Beginning of Rate Year)	$ 76,239	A
2	Amortization Period (Years)	3	
3	Amortization Expense	$ 25,413	
4	Depreciation Expense Per Company (Plant Account 391CB)	$ 69,107	B
5	Division Adjustment to Depreciation Expense	$ (43,694)	

Notes and Source

A: Amount from column E, line 18 below, using data from Exhibit 4 (Gil), Schedule 3, Plant Account 391CB

	Date	CIS Plant Amount (B)	Accumulated Depreciation (C)	Depreciation Expense (D)	Net Plant In Service (E)
6	9/30/2017	$ 552,856	$ (407,511)		$ 145,345
7	10/31/2017	$ 552,856	$ (413,269)	$ 5,758	$ 139,587
8	11/30/2017	$ 552,856	$ (419,028)	$ 5,759	$ 133,828
9	12/31/2017	$ 552,856	$ (424,787)	$ 5,759	$ 128,069
10	1/31/2018	$ 552,856	$ (430,546)	$ 5,759	$ 122,310
11	2/28/2018	$ 552,856	$ (436,305)	$ 5,759	$ 116,551
12	3/31/2018	$ 552,856	$ (442,064)	$ 5,759	$ 110,792
13	4/30/2018	$ 552,856	$ (447,823)	$ 5,759	$ 105,033
14	5/31/2018	$ 552,856	$ (453,582)	$ 5,759	$ 99,274
15	6/30/2018	$ 552,856	$ (459,341)	$ 5,759	$ 93,515
16	7/31/2018	$ 552,856	$ (465,100)	$ 5,759	$ 87,756
17	8/31/2018	$ 552,856	$ (470,859)	$ 5,759	$ 81,997
18	9/30/2018	$ 552,856	$ (476,617)	$ 5,759	$ 76,239

B: Page 1, Column L, Line 26

Suez Water Rhode Island, Inc.
Wages and Salaries Expense

Rate Year Ending September 30, 2019

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Line No.	Description	Per Company (A)	Per Division (B)	Division Adjustment (C)
1	Rate Year Payroll Expense Per Company	$ 837,587	$ 791,158	$ (46,429)
2	Capitalization Percentage	23.03%	24.42%	
3	Less: Capitalized Payroll Expense	$ (192,879)	$ (193,205)	$ (325)
4	Labor Transferred In	$ 10,023	$ 8,531	$ (1,492)
5	Total Rate Year O&M Payroll Expense	$ 654,731	$ 606,484	$ (48,247)

Notes and Source
Col. A: Amounts from Exhibit 3 (Arp), Schedule 2A from SWRI's filing
Col. B: Division recommended Rate Year payroll expense calculated below (see page 2, line 6 for capitalization percentage):

Line No.	Job Title	FLSA (D)	Projected 2019 Base Salary (E)	Incentive Compensation Target % (F)	Incentive Compensation (G)	Overtime* (H)	Total Rate Year Payroll Expense (I)
6	Mgr Rhode Island	Exempt	$ 118,294	15%	$ 17,744	$ -	$ 136,038
7	Foreman	Exempt	$ 72,260	10%	$ 7,226	$ -	$ 79,486
8	Supv Customer Contact&Billing	Exempt	$ 74,263	10%	$ 7,426	$ -	$ 81,689
9	Superintendent	Exempt	$ 98,536	5%	$ 4,927	$ -	$ 103,463
10	Chief Operator	Non-exempt	$ 69,179	3%	$ 2,075	$ 11,999	$ 83,254
11	Meter Reader	Non-exempt	$ 54,394	3%	$ 1,632	$ 9,435	$ 65,461
12	Sr Cust Serv Rep	Non-exempt	$ 54,019	3%	$ 1,621	$ 9,370	$ 65,010
13	Sr Cust Serv Rep	Non-exempt	$ 51,107	3%	$ 1,533	$ 8,864	$ 61,504
14	Service Person	Non-exempt	$ 50,290	3%	$ 1,509	$ 8,723	$ 60,522
15	Service Person	Non-exempt	$ 45,480	3%	$ 1,364	$ 7,888	$ 54,732
16	Customer service/data entry tech	Non-exempt	$ -		$ -	$ -	$ -
17	Total Payroll Expense		$ 687,822		$ 47,057	$ 56,279	$ 791,158

Line No.	Description	Amount	Reference
18	Total Rate Year Payroll Expense Per SWRI	$ 791,158	Line 17
19	Labor Transferred In Percentage (page 2)	1.08%	Page 2, Line 8
20	Labor Transferred In Per Division	$ 8,531	L18 x L19

* **Rate Year Overtime**

Line No.		Year	Hours	Overtime	Hourly Rate
21		2015	1,450	$ 54,323	$ 37.46
22		2016	1,426	$ 51,907	$ 36.40
23		9/30/2017	1,460	$ 53,580	$ 36.71
24	3-Year Hours Average x Test Year Hourly Rate		1,445	$ 53,048	
25	Overtime with Compound Salary Increase of 6.09%			$ 56,279	

Line No.	Job Title	Projected 2019 Base Salary Reflecing 3% Increase	Overtime Allocation as a Percentage of Base Pay	Rate Year Overtime with 3% Increase
26	Chief Operator	$ 69,179	21.32%	$ 11,999
27	Meter Reader	$ 54,394	16.76%	$ 9,435
28	Sr Cust Serv Rep	$ 54,019	16.65%	$ 9,370
29	Sr Cust Serv Rep	$ 51,107	15.75%	$ 8,864
30	Service Person	$ 50,290	15.50%	$ 8,723
31	Service Person	$ 45,480	14.02%	$ 7,888
32	Customer service/data entry tech	$ -		
33	Total	$ 324,469	100.00%	$ 56,279

Suez Water Rhode Island, Inc.
Wages and Salaries Expense

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule C-2
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Line No.	Description	2015	2016	Test Year Ended 9/30/2017	3-Year Average
		(A)	(B)	(C)	(D)
1	Gross Payroll Expense	$ 684,882	$ 707,293	$ 682,794	$ 691,656
2	Less: Capitalized Portion	$ (163,142)	$ (164,632)	$ (178,651)	$ (168,808)
3	Net Payroll Expense	$ 521,741	$ 542,661	$ 504,143	$ 522,848
4	Expense Rate	76.18%	76.72%	73.84%	75.58%
5	Capitalized	$ (163,142)	$ (164,632)	$ (178,651)	$ (126,606)
6	Capitalized Rate	23.82%	23.28%	26.16%	**24.42%**
7	Transferred in	$ 8,414	$ 6,341	$ 7,578	$ 7,444
8	Transferred in Rate	1.23%	0.90%	1.11%	**1.08%**

Notes and Source
Amounts above from Exhibit 3 (Arp), Schedule 2B from SWRI's filing

Suez Water Rhode Island, Inc.
Incentive Compensation Expense

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule C-3
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Line No.	Description	Amount (A)	Reference
1	Adjustment to Incentive Compensation Expense	$ (35,337)	A

Notes and Source

A: Division recommended adjustment to incentive compensation calculated below using data from the response to DPU 3-3:

	Description	Account	O&M Short-Term Incentive Plan Amount (B)	O&M Long-Term Incentive Plan Amount (C)	Division Adjustment (D)
2	Supv Lbr-T&D Maint Sup & Eng	50100670	$ 5,700		
3	Supv Lbr-A&G Ops Salaries	50100920	$ 23,476		
4	Corporate Shared Services Fees	90850923	$ 32,304	$ 10,745	
5	Total		$ 61,480	$ 10,745	$ -
6	Division Recommended Disallowance Percentage		40.00%	100.00%	
7	Amount of Disallowed Incentive Compensation Expense		$ (24,592)	$ (10,745)	$ (35,337)

Suez Water Rhode Island, Inc.
Payroll Tax Expense

Rate Year Ending September 30, 2019

Exhibit RCS-2
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Line No.	Description	Reference	Payroll Related Adjustment	FICA Tax* 6.20%	Medicare Tax 1.45%	Payroll Tax Expense Adjustment
			(A)	(B)	(C)	(D)
1	Division Adjustment to Wages and Salaries Expense	A	$ (48,247)	$ (2,991)	$ (700)	$ (3,691)
2	Division Adjustment to Incentive Compensation Expense	B	$ (35,337)	$ (2,191)	$ (512)	$ (2,703)
3	Total of Division Adjustments Listed Above		$ (83,584)	$ (5,182)	$ (1,212)	$ (6,394)

Notes and Source
A: See Schedule C-2
B: See Schedule C-3

* The maximum amount of wages in 2018 subject to the 6.20% Social Security tax is $128,400. To the extent that the salaries of certain individuals included in the adjustments listed are above the threshold of $128,400, it will be necessary to modify this adjustment to Payroll Tax expense.

Suez Water Rhode Island, Inc.
Property Tax Expense

Rate Year Ending September 30, 2019

Exhibit RCS-2
Schedule C-5
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Line No.	Description	Amount (A)	Reference
1	Rate Year Property Tax Expense per Division	$ 398,640	A
2	Rate Year Property Tax Expense per SWRI	$ 409,722	B
3	Adjustment to Property Tax Expense	$ (11,082)	

Notes and Source:
A: Amount from Exhibit 3 (Arp), Schedule 18 from SWRI's filing
B: Using the data from Exhibit 3 (Arp), Schedule 18, Division recommendation based on using a 3-year average which is calculated below:

	Description	Amount (B)	Change (C)	Percentage Change (D)
4	2014 Actual Property Tax Expense	$ 322,959		
5	2015 Actual Property Tax Expense	$ 334,442	$ 11,483	3.56%
6	2016 Actual Property Tax Expense	$ 343,043	$ 8,601	2.57%
7	2017 Actual Property Tax Expense	$ 366,378	$ 23,335	6.80%
8	3 Year Average Increase in Property Tax Expense			4.31%
9	2018 Projected Property Tax Expense	$ 382,168		
10	2019 Projected Property Tax Expense	$ 398,640		

Suez Water Rhode Island, Inc.
Transportation & Vehicle Lease Expense

Rate Year Ending September 30, 2019

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Schedule C-6
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Line No.	Description	Rate Year Amount Per Company (A)	Rate Year Amount Per Division (B)	Division Adjustment (C)	Division Rate Year Amount Reference
1	Leases	$ 34,362	$ 26,981	$ (7,381)	Page 2
2	Fuel	$ 20,569	$ 17,785	$ (2,784)	Line 16
3	Maintenance & Repair	$ 11,313	$ 6,480	$ (4,834)	Line 22
4	Insurance	$ 6,291	$ 5,368	$ (922)	Line 28
5	Depreciation	$ 1,643	$ 1,643	$ -	
6	Other - Registration, Plates, Tolls, Mileage, Etc.	$ 5,811	$ 5,222	$ (589)	Line 34
7	Total Costs	$ 79,989	$ 63,479	$ (16,510)	
8	Capitalization Percentage	23.03%	24.42%		Sch. C-2
9	Less: Capitalized Portion	$ (18,420)	$ (15,502)	$ 2,918	
10	Net Transportation & Vehicles Expense	$ 61,569	$ 47,977	$ (13,592)	

Notes and Source:
Amounts below from Exhibit 2 (Arp) Schedule 10A from SWRI's filing

Line	Description	Rate Year Per Division
	Fuel	
11	2015 Fuel Costs	$ 17,337
12	2016 Fuel Costs	$ 17,732
13	Test Year Ended 9/30/2017 Fuel Costs	$ 15,403
14	3 Year Average Fuel Costs	$ 16,824
15	Inflation Rate	5.714%
16	Inflation Adjusted 3 Year Average Fuel Costs	$ 17,785
	Maintenance & Repair	
17	2014 Maintenance & Repair Expense	$ 3,753
18	2015 Maintenance & Repair Expense	$ 5,522
19	2016 Maintenance & Repair Expense	$ 9,113
20	3-Year Average Maintenance & Repair Expense	$ 6,129
21	Inflation Rate	5.714%
22	Inflation Adjusted Maintenance & Repair Expense	$ 6,480
	Insurance	
23	2014 Insurance Expense	$ 4,907
24	2015 Insurance Expense	$ 6,055
25	2016 Insurance Expense	$ 4,273
26	3-Year Average Insurance Expense	$ 5,078
27	Inflation Rate	5.714%
28	Inflation Adjusted Insurance Expense	$ 5,368
	Other Miscellaneous	
29	2014 Miscellaneous Expense	$ 4,770
30	2015 Miscellaneous Expense	$ 5,882
31	2016 Miscellaneous Expense	$ 4,167
32	3-Year Average Miscellaneous Expense	$ 4,940
33	Inflation Rate	5.714%
34	Inflation Adjusted Miscellaneous Expense	$ 5,222

Suez Water Rhode Island, Inc.
Transportation & Vehicle Lease Expense

Rate Year Ending September 30, 2019

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Line No.	Vehicle	Lease Number	Lease Start Date	Lease End Date	Rate Year Monthly Lease Amount	Rate Year Annual Lease Amount
	(A)	(B)	(C)	(D)	(E)	(F)
	Per SWRI					
1	002	1430	9/1/2011	8/30/2017	$ 13	$ 156
2	026	110105	11/1/2011	10/31/2017	$ 13	$ 156
3	027	110196	9/1/2012	8/31/2018	$ 750	$ 9,000
4	024	110197	9/1/2012	8/31/2018	$ 520	$ 6,240
5	JACOBS	110364	5/1/2014	4/30/2020	$ 465	$ 5,574
6	JACOBS	110527	4/1/2016	3/31/2022	$ 512	$ 6,146
7	JACOBS	86251	5/1/2014	4/30/2020	$ 591	$ 7,090
8	Total Annual Costs					$ 34,362
	Per Division					
9	002	1430	9/1/2011	8/30/2017	$ -	$ -
10	026	110105	11/1/2011	10/31/2017	$ -	$ -
11	027	110196	9/1/2012	8/31/2018	$ 386	$ 4,628
12	024	110197	9/1/2012	8/31/2018	$ 295	$ 3,543
13	JACOBS	110364	5/1/2014	4/30/2020	$ 465	$ 5,574
14	JACOBS	110527	4/1/2016	3/31/2022	$ 512	$ 6,146
15	JACOBS	86251	5/1/2014	4/30/2020	$ 591	$ 7,090
16	Total Annual Costs					$ 26,981
17	Division Adjustment to Vehicle Lease Expense					$ (7,381)

Notes and Source

Amounts above from Exhibit 2 (Arp) Schedule 10B from SWRI's filing

Suez Water Rhode Island, Inc.
Management & Services Expense

Rate Year Ending September 30, 2019

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Line No.	Description	Amount	Reference
		(A)	
1	Rate Year Management & Services Expense Per Company	$ 509,952	A
2	Rate Year Management & Services Expense Per Division	$ 445,215	B
3	Adjustment to Management & Services Expense	$ (64,736)	L2 - L1

Notes and Source:
A: Amount from Exhibit 3 (Arp), Schedule 14A from SWRI's filing
B: Division recommended Rate Year level of Management & Services Expense calculated below using data from Exhibit 3 (Arp) Schedule 14A (except where noted)

	Description	2015	2016	2017*	3-Year Average
		(B)	(C)	(D)	(D)
4	Management & Services Expense	$ 410,381	$ 463,490	$ 461,774	$ 445,215

* Calendar year 2017 amount from the response to DPU 9-37

Suez Water Rhode Island, Inc.
Chemical Expense

Rate Year Ending September 30, 2019

Line No.	Description	Amount (A)	Reference
1	Rate Year Chemical Expense Per SWRI	$ 45,171	A
2	Rate Year Chemical Expense Per Division	$ 46,283	B
3	Adjustment to Chemical Expense	$ 1,113	L2 - L1

Notes and Source

A: Amount from Exhibit 3 (Arp), Schedule 5 from SWRI's filing

B: Division recommended Rate Year Chemical Expense calculated below using data from Exhibit 3 (Arp), Schedule 5A:

	Description	UOM	Usage	Projected Water Production (MG) [a]	Average Usage Per MG [b]	Chemical Unit Price	Total Cost
4	Lime	lbs	105,373	931	113.12	$ 0.1916	$ 20,192
5	Sodium Hypocloride	gals	9,831	931	10.55	$ 1.5310	$ 15,051
6	Zinc Orthophosphate (Klenphos K-10)	lbs	18,625	931	20.00	$ 0.5928	$ 11,040
7	Total						$ 46,283

[a]	**Calculation of Projected Water Production (MG)**	Amount	Reference
8	Billed Consumption (MG)	912	Exh. 2 (Gil), Sch. 2
9	Non-revenue water %	2.06%	Line 14
10	Total Production Subject to Chemical Treatment (MG)	931	L9 x L10

	Date	Non-Water Rev%
11	2015	3.99%
12	2016	1.76%
13	9/30/2017	0.44%
14	3-Year Avg.	2.06%

[b] Calculation of Average Usage Per MG

	Description	Lime	Sodium Hypocloride	Zinc Orthophosphate (Klenphos K-10)
15	Year Ended 12/31/2015	104.55	9.04	16.13
16	Year Ended 12/31/2016	114.58	10.84	21.08
17	Test Year Ended 9/30/2017	120.25	11.78	22.79
18	3-Year Average of Usage Per MG	113.12	10.55	20.00

Suez Water Rhode Island, Inc.
Power Expense

Rate Year Ending September 30, 2019

Exhibit RCS-2
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Line No.	Description	Amount (A)	Reference
1	Rate Year Power Expense Per SWRI	$ 363,086	A
2	Rate Year Power Expense Per Division	$ 340,887	B
3	Adjustment to Power Expense	$ (22,199)	L2 - L1

Notes and Source

A: Amount from Exhibit 3 (Arp), Schedule 4 from SWRI's filing

B: Division recommended Rate Year Power Expense calculated below using data from Exhibit 3 (Arp), Schedule 4A:

	Description	kWh	Projected Water Production (MG)	[a]	kWh 3 Yr. Avg. Usage	[b]	kWh Avg. Cost	Total Cost	
4	Commodity (Engie Resources, LLC)	1,630,963	931		1,751		$ 0.0850	$ 138,632	
5	Distribution (National Grid)	1,630,963	931		1,751		$ 0.1067	$ 174,024	
6	Total Rate Year - Account 50610							$ 312,656	
7	Other Utilities - Power Account 50620							$ 28,231	Line 24
8	Total Rate Year Power Expense Per Division							$ 340,887	

[a]	**Calculation of Projected Water Production (MG)**	Amount	Reference
9	Billed Consumption (MG)	912	Exh. 2 (Gil), Sch. 2
10	Non-revenue water %	2.06%	Line 15
11	Total Production Subject to Chemical Treatment (MG)	931	L9 x L10

	Date	Non-Water Rev%
12	2015	3.99%
13	2016	1.76%
14	9/30/2017	0.44%
15	3-Year Avg.	2.06%

[b]	**Calculation of kWh Average Usage**	Date	
16	Commodity & Distribution	12/31/2015	1,747
17	Commodity & Distribution	12/31/2016	1,810
18	Commodity & Distribution	9/30/2017	1,696
19		3-Year Avg.	1,751

	Calculation of Other Utilites Power	Date	Amount
20		2015	$ 31,106
21		2016	$ 18,623
22		9/30/2017	$ 30,386
23		3-Year Avg.	$ 26,705
24	Inflation Factor	5.714%	$ 28,231

Suez Water Rhode Island, Inc.
Interest Synchronization

Rate Year Ending September 30, 2019

Exhibit RCS-2
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Line No.	Description		Amount (A)	Reference
1	Adjusted Rate Base, per Division	$	20,241,177	Schedule B
2	Weighted Cost of Debt, per Division		2.13%	Per Division - Schedule D
3	Going-Level Interest Deduction for Tax Purposes	$	431,137	L1 x L2
4	Interest Deduction per Company	$	437,556	Note A
5	Decrease in Deductible Interest	$	(6,419)	L3 - L4
6	Federal Income Tax Rate		21.00%	
7	Increase to Federal Income Tax Expense	$	1,348	L8 x L9

Notes and Source:
A: Amount from Exhibit 4 (Gil), Schedule 21 from SWRI's filing

SUEZ Water Rhode Island, Inc.
Federal Income Tax Expense
To reflect Federal Income expense based upon Rate Year changes in taxable income at present and proposed rates

Rate Year Ending September 30, 2019

Line No.	Description	Rate Year Per Company Present Rates (A)	Rate Year Per Company Proposed Rates (B)	(C)	Rate Year Per Division Present Rates (D)	Rate Year Per Division Proposed Rates (E)
1	Revenues	$ 4,813,887	$ 5,838,744		$ 4,813,887	$ 5,249,190
2	Operating Expenses:					
3	Operation and Maintenance	$ 2,510,506	$ 2,514,887		$ 2,327,507	$ 2,329,368
4	Depreciation and Amortization	$ 905,502	$ 905,502		$ 852,271	$ 852,271
5	Taxes other than income	$ 536,842	$ 549,653		$ 519,366	$ 524,807
6	Operating Expenses Before Income Taxes	$ 3,952,850	$ 3,970,042		$ 3,699,144	$ 3,706,446
7	Operating Income Before Income Taxes	$ 861,037	$ 1,868,701		$ 1,114,743	$ 1,542,744
8	Interest Expense	$ 437,556 [a]	$ 437,556 [a]		$ 431,137	$ 431,137
9	Federal Taxable Income	$ 423,481	$ 1,431,146		$ 683,606	$ 1,111,607
10	Federal Income Tax Rate	21%	21%		21%	21%
11	Federal Income Tax	$ 88,931	$ 300,541		$ 143,557	$ 233,437
12	Amortization of Reg Liability TCJA [b]	$ (33,604)	$ (33,604)		$ (98,867)	$ (98,867)
13	Amortization of ITC	$ (4,662)	$ (4,662)		$ (4,662)	$ (4,662)
14	Total Federal Income tax	$ 50,666	$ 262,275		$ 40,028	$ 129,908

Notes and Source
Cols. A&B: Amounts from Exhibit 3 (Gil), Schedule 21

Line No.	[a] Interest Expense	Per Company		Per Division	
16	Rate Base	$ 20,542,518	$ 20,542,518	$ 20,241,177	$ 20,241,177
17	Weighted Cost of Debt	2.13%	2.13%	2.13%	2.13%
18	Interest Expense	$ 437,556	$ 437,556	$ 431,137	$ 431,137

Line 15: [a] Interest Expense

[b] TCJA Regulatory Liability and Amortization

Line No.	Description	Per Company Regulatory Liability Amount (A)	Per Company Amortization Period in Years (B)	Per Company Annual Amortization (C)	Per Division Regulatory Liability Amount (D)	Per Division Amortization Period in Years (E)		Per Division Annual Amortization (F)	Division Adjustment (G)=F-C
19	"Protected" Excess ADIT	$ (1,601,632)	50	$ (32,033)	$ (1,546,589)	50	[c]	$ (30,932)	
20	"Unprotected" Excess ADIT	$ 51,092	50	$ 1,022	$ (3,951)	3		$ (1,317)	
21	Subtotal Excess ADIT	$ (1,550,539)		$ (31,011)	$ (1,550,539)			$ (32,249)	
22	2018 Federal Income Tax Savings Through 9/30/2018	$ (129,640)	50	$ (2,593)	$ (199,855)	3		$ (66,618)	
23	Total	$ (1,680,180)		$ (33,604)	$ (1,750,395)			$ (98,867)	$ (65,263)

[c] The Company's proposed 50-year amortization is currently being used as a placeholder, and should be updated to reflect more accurate information.

SUEZ Water Rhode Island, Inc.
Federal Income Tax Savings in 2018 from Reduction in Federal Income Tax
Rate from 35 Percent to 21 Percent

Rate Year Ending September 30, 2019

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Line No.	Description	Regulatory Liability Per Company: Federal Income Tax Savings	Gross-Up	Regulatory Liability	Cumulative Regulatory Liability	Amortization of Estimated 9/30/2018 Balance at Rate Effective Date	Cumulative Federal Income Tax Savings	Amortization of Estimated 9/30/2018 Balance at Rate Effective Date
		(A)	(B)	(C)=A+B	(D)	(E)	(F)	(G)
1	January Through April 30, 2018	$ 36,494	$ 9,701	$ 46,195	$ 46,195		$ 36,494	
2	May 31, 2018	$ 16,480	$ 4,381	$ 20,861	$ 67,056		$ 52,974	
3	June 30, 2018	$ 29,968	$ 7,966	$ 37,934	$ 104,990		$ 82,942	
4	July 31, 2018	$ 40,061	$ 10,649	$ 50,711	$ 155,701		$ 123,003	
5	August 31, 2018	$ 44,935	$ 11,945	$ 56,880	$ 212,581		$ 167,938	
6	September 30, 2018	$ 31,917	$ 8,484	$ 40,402	$ 252,983	$ (84,328)	$ 199,855	$ (66,618)
7	October 31, 2018	$ 11,174	$ 2,970	$ 14,144	$ 267,127		$ 211,029	
8	November 30, 2018	$ 7,890	$ 2,097	$ 9,988	$ 277,115		$ 218,919	
9	December 31, 2018	$ 9,860	$ 2,621	$ 12,481	$ 289,596		$ 228,779	
10	Totals	$ 228,779	$ 60,814	$ 289,596				

Notes and Source
Line 1: Company's response to DPU 9-7 Attachment
Lines 2-9: Company's repsonse to DPU 9-8 Attachment

Line 6, Col. E: Illustration shows amortization of cumulative September 30, 2018 balance over three years, based on an estimated effective date for new rates set in ths case of October 1, 2018. The three-year period used for this amortization corresponds with the Company's proposed three-year amortization period for rate case expense.

Col. F: Cumulative federal income tax savings from Column A

SUEZ Water Rhode Island, Inc.
Accumulated Deferred Income Tax and Excess Accumulated Deferred Income Tax
Regulatory Liability Balances as of December 31, 2017

Rate Year Ending September 30, 2019

Line No.	Account	Description	Suez Water Calculation of ADIT Balance at 12/31/2017 (A)	Suez Water Calculation of ADIT Balance at 21% (B)	Regulatory Liability For Excess ADIT (C)=A-B	Division Proposal Before Gross-Up: Protected Excess ADIT (D)	Division Proposal Before Gross-Up: Non-Protected Excess ADIT (E)	Division Proposal After Gross-Up: Protected Excess ADIT (F)	Division Proposal After Gross-Up: Non-Protected Excess ADIT (G)	Division Proposal After Gross-Up: Total Regulatory Liability For Excess ADIT (H)
1	19010	Def. Federal Inc Taxes - Other	$ (519)	$ (311)	$ (208)		$ (208)		$ (263)	
2	28203	Def. FIT-MACRS	$ (3,054,514)	$ (1,832,709)	$ (1,221,805) [3]	$ (1,221,805)		$ (1,546,589)		
3	28207	Def FIT Pens Reg Asset FAS158	$ (342,291)	$ (205,375)	$ (136,916)		$ (136,916)		$ (173,311)	
4	28208	Def FIT Pens PBOP Reg Asset FAS158	$ (777)	$ (466)	$ (311)		$ (311)		$ (394)	
5	28300	Def. FIT - Other	$ 68,287	$ 40,972	$ 27,315		$ 27,315		$ 34,576	
6	28301	Def. FIT - Tank Painting	$ 26,626	$ 15,976	$ 10,650 [3]		$ 10,650		$ 13,481	
7	28302	Def. FIT - Rate Expenses	$ (2,590)	$ (1,554)	$ (1,036)		$ (1,036)		$ (1,311)	
8	28306	Def. FIT Pensions	$ 97,008	$ 58,205	$ 38,803		$ 38,803		$ 49,118	
9	28307	Def. FIT PEBOP	$ 263,025	$ 157,815	$ 105,210		$ 105,210		$ 133,177	
10	28308	Def. FIT - Cost of Removal	$ (55,074)	$ (33,044)	$ (22,030) [3]		$ (22,030)		$ (27,886)	
11	28310	Def. FIT - Uncollectibles	$ 432	$ 259	$ 173		$ 173		$ 219	
12	28311	Def. FIT - Injuries and Damages	$ 18,333	$ 11,000	$ 7,333		$ 7,333		$ 9,282	
13	28312	Def. FIT - AFUDC Equity	$ (80,261)	$ (48,157)	$ (32,104) [3]		$ (32,104)		$ (40,638)	
14		Total Deferred Tax Before TCJA Impact	$ (3,062,315)	$ (1,837,389)	$ (1,224,926)	$ (1,221,805)	$ (3,121)	$ (1,546,589)	$ (3,951)	$ (1,550,539)
15	28402	Def. FIT - New Federal Tax Rate	$ (1,224,926) [1]							
16	28405	Def. FIT - New Federal Tax Rate Gross-Up	$ (325,613) [2]	$ (325,613)						
17		Accumulated Deferred Income Taxes	$ (1,511,776)	$ (1,511,776)						
18	25316	Regulatory Liability - Tax New Federal Rate	$ (1,550,539)	$ (325,613)						
19		Total ADIT and Regulatory Liability After TCJA Impact	$ (3,062,315)							
								Company Proposal With Gross-Up		
20						$ (1,265,289)	$ 40,363	$ (1,601,632)	$ 51,092	$ (1,550,539)
21		Difference						$ 55,043	$ (55,043)	$ -

[1] Confirmation of the calculation of the amount change due to rate: Line 14 times (.35 - .21) / .35
[2] Confirmation of the calculation gross-up of the amount change due to rate: Line 15 times .21 divided by (1 - .21)
[3] Suez Water proposed "protected" excess ADIT

Notes and Source
Cols. A&B: Company response to DPU 9-1 Attachment. (Negative amounts) indicate credit balances, i.e., liabilities. Positive amounts indicate debits.