STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: PASCOAG UTILITIES DISTRICT	**:**	
APPLICATION TO CHANGE ELECTRIC	**:**	**DOCKET NO. 5134**
BASE DISTRIBUTION RATES	**:**	

REPORT AND ORDER

I. Introduction

On March 19, 2021, the Pascoag Utilities District (Pascoag) filed with the Public Utilities Commission (Commission) a request seeking to implement new rate schedules which would take effect on October 1, 2021, designed to collect additional revenue in the amount of $379,332, or an increase of 4.72% over test year revenues for a total revenue requirement of $3,132,003, excluding purchase power expenses.[1] The Commission suspended Pascoag's filing on April 14, 2021. This was Pascoag's first base rate case filing since 2012, and the second such filing since 2003.

II. Pascoag's Filing

In support of its filing, Pascoag presented prefiled testimony from Michael R. Kirkwood, Pascoag's General Manager/CEO, and David Bebyn, CPA, its consultant. As required by R.I. Gen. Laws § 39-1-27.8, each electric distribution company must submit annually a supply procurement plan for approval by the PUC. Pascoag submits its plan as part of its Standard Offer Service Reconciliation each year.

Mr. Kirkwood's Testimony

Mr. Kirkwood provided testimony to discuss the issues and challenges facing Pascoag and how he intends to meet them. He noted that his philosophy is to take advantage of technological advances when it is cost effective to do so and when the cost of such becomes

[1] All filings in this docket are available at the PUC offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at http://www.ripuc.org/eventsactions/docket/5134page.html.

stable and affordable. He stated that over the past few years, Pascoag has deployed Automatic Meter Reading (AMR) meters that it was able to acquire from a company that refurbished and retested previously used meters resulting in a significant savings to Pascoag. In addition to significant meter cost savings, installing the AMR meters substantially reduced meter reading time and improved billing accuracy by considerably reducing the chance of human error. Within the next five years, Pascoag intends to examine and test Intelligent Meter Reading (IMR) meters[2] which it will eventually transition to when they become more stable and cost efficient.[3]

Mr. Kirkwood explained that the feeder lines from National Grid were beginning to meet their limits during peak conditions. In response, Pascoag reconfigured the substation to allow for greater electrical capacity across these lines during non-contingency conditions. It also installed a 3 MW/9MWh battery storage device that will allow Pascoag to maintain delivery even under N-1 emergency conditions during peak load times. The decision to upgrade the substation and install the battery storage device saved Pascoag approximately $6 million by avoiding the rebuild of two feeder lines.[4]

Mr. Kirkwood expressed that the five-year capital budget process has been effective in maintaining reliability, because it has allowed Pascoag to replace aging vehicles which it has done with new vehicles with lower emissions. It also funds computer, meters, streetlights, poles, transformers, distribution wire and cable and other items. He noted that Pascoag purchased the AMR meters and its customer information, accounting, and work management systems with capital funds. He described a number of upcoming capital projects planned for the next five years to include 1) substation enhancements and

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[2] IMR or Intelligent meters are synonymous with Advanced Metering Infrastructure (AMI) meters.
[3] Kirkwood Test. at 1-2 (Mar. 19, 2021).
[4] *Id.* at 3.

maintenance, 2) IT system reliability upgrades, 3) a study or pilot to examine migration from the AMR meters to real time based IMR meter technology, and 4) fleet replacements. Mr. Kirkwood stated that he expects Pascoag's capital funding to remain the same and that the current $306,200 annual funding amount should be sufficient to allow continuation of its programs that have been successful in past years.[5]

Noting that during Pascoag's last rate case it had concerns about losing its largest customer, Daniele Prosciutto Inc. (DPI), due to the construction of a new facility located outside of Pascoag's service territory, Mr. Kirkwood reported that increased sales appear to have necessitated the continued operation of the existing DPI facility for the foreseeable future. He stated although DPI's load and contribution to Pascoag's revenues have decreased over the past few years, DPI is still Pascoag's largest customer that it has worked with and will continue to work with to make its facilities more efficient.[6]

Addressing the proposed changes to the commercial and industrial (C&I) class, Mr. Kirkwood explained how some of Pascoag's small commercial customers were being charged disproportionately. He stated that this was because while they have a high peak kW, they have lower usage kWh. Because C&I customers are charged from a $/kW demand component, these customers are being disproportionately charged. Mr. Kirkwood provided that Pascoag is proposing three revisions creating new C&I classes that will more fairly allocate costs across the various businesses in the C&I customer base. The first class would be a Small Commercial B for customers under 15 kW which would have a distribution cost component based solely on $/kWh. The second class would be a General Service Class for customers over 15 kW but under 200 kW which would have a distribution

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[5] *Id.* at 4-5.
[6] *Id.* at 5-6.

cost component based on 50% $/kWh and 50% $/kW. The final class would be a General Service Class for customers over 200 kW which would have a distribution cost component based solely on $/kW. He noted that these classes would be explained fully by Mr. Bebyn.[7]

Discussing the proposed changes to Pascoag's net metering policy, Mr. Kirkwood stated they were necessary because the policy is not operating as intended. He explained that currently one meter is used and any generation provided by the customer is netted first against the customer's actual usage. He noted that this is inconsistent with the current policy that intends for customer generation to be credited for Last Resort (formerly known as Standard Offer Service) for what is being generated without first netting that generation against the customer's load. In order for Pascoag to ascertain the actual customer load, it needs to set up a two-meter system for future net metering customers which will allow it to determine full customer load and full generation of the approved system. Currently seven customers are operating with one meter, Pascoag proposed allowing these customers to continue with one meter.[8]

Mr. Bebyn's Testimony

Mr. Bebyn filed testimony to present the test year, rate year, proposed rate design, and ratepayer impacts. He noted that Pascoag's needed increase is due to expenditures and funding of reserves exceeding current revenues and new Division approved debt to cover eligible energy efficiency projects. He provided that Pascoag was requesting an additional $379,332 in revenue for a total revenue requirement of $3,132,003, which is 4.72% over the test year revenue including power costs and 13.78% over the adjusted rate year revenue excluding purchase power costs at current rates.[9]

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[7] *Id.* at 6-7.
[8] *Id.* at 7-8.
[9] Bebyn Test. at 1-2 (Mar. 19, 2021).

Mr. Bebyn used July 1, 2019 to June 30, 2020 as the test year and made a number of adjustments to normalize it. He noted that most of Pascoag's revenue is pass-through that it receives for purchase power expense, which is eliminated from the revenue requirement because it is collected at the end of the year through a reconciliation proceeding before the Commission. He identified the distribution and demand service charge as Pascoag's second largest source of revenue that includes kWh distribution charges for its residential and commercial customers as well as kW demand charges for its industrial customers. The third source of revenue he discussed was the revenue Pascoag receives from customer charge which he stated had grown so minimally since the last rate case that he made no adjustment. Finally, he noted other revenues such as public street lighting, private street lighting, and power factor which were left at test year levels. He projected rate year revenue at current rates to be $2,752,671 which does not include pass through revenue.[10]

Like he did with revenue, Mr. Bebyn eliminated the purchase power pass-through expense when calculating expense balances. Regarding payroll expense, he increased salaries by 3-4% in the interim year and then again for anticipated salary increases during the rate year. He provided that the number of current employees is sufficient for operations during the rate year. Mr. Bebyn stated that he averaged a number of expense accounts that had no specific trend in increases or decreases over a five-year period. These accounts reduced expenses. He left certain accounts at test year levels, because they were small accounts and in order to save rate case time and expense. He increased the custodial expense account to reflect an increase in additional time required to clean and in cleaning products needed because of COVID.[11]

[10] *Id.* at 3-8.
[11] *Id.* at 9-11.

Continuing to discuss expense adjustments, Mr. Bebyn noted the reduction made to account for Pascoag's water division employees. He increased legal services expense by using a three-year average and reflected the costs of a new three-year contract for auditing services. Because Pascoag implemented additional cybersecurity, Mr. Bebyn increased the Outside services-computer/IT account. He amortized the $86,000 rate case expense which includes the cost of the Division's consultants, legal fees, legal notices, printing expense, and his charges over the course of three years. He increased the Good Neighbor Energy Fund account to reflect costs associated with Pascoag hosting the event in 2021 and increased property insurance expense by 5% allocating 80% of that increase to the electric division and the remaining 20% to the water division.[12]

Regarding the employee benefit expense accounts, Mr. Bebyn made an adjustment to increase health and dental insurance noting that employees pay 20% toward their health insurance coverage. He reduced the schools and seminar expense and reflected the cost of health care expense provided to Board members who receive a $3,000 stipend with only one Board member remaining still eligible to participate in Pascoag's healthcare plan. This cost was also allocated between the electric and water divisions. Mr. Bebyn increased the Defined Benefit Plan expense using payroll and salary figure to reflect Pascoag's 10% contribution to this Plan.[13]

Mr. Bebyn made no changes to future capital improvement or Storm Contingency funds. He increased social security and Medicare payroll taxes. He stated that Pascoag needs $113,600 to cover principal and interest costs from a Division-approved subsidized

[12] *Id.* at 12-14.
[13] *Id.* at 14-16.

loan from the Rhode Island Infrastructure Bank. In addition to this, it needs an additional $28,400 to maintain 125% coverage required by the bond indentures.[14]

Mr. Bebyn also addressed Pascoag's proposed rate design. He noted that after the last rate case, costs were allocated only at a peak kWh allocation. He stated that costs for residential and commercial customers were divided by kWh sales to determine the rate while large commercial and industrial customers used kW demand to determine their rate and used a demand ratchet. He noted that many of the smaller demand users who barely triggered the 15 kW floor for a few months per year over contributed. To resolve this, Pascoag proposed a seasonal rate.[15]

Mr. Bebyn proposed five changes to Pascoag's rate design. The first change related to how the demand/distribution costs were allocated between classes. He proposed using kW demand by customer class for the month when Pascoag experiences its peak. He reasoned that this will reflect the true impact on the system demand from the class causing those demands. The second change he proposed was to make some customer class changes. The proposed classes are Residential, Commercial, General Services <200kW, General Services > 200kW, and Municipal Low Capacity Factor Rate. His rationale for separating the large C&I customers into two groups was because the smaller commercial accounts using 16kW were being charged the same rate as the larger commercial accounts using more than 200kW and being charged for all of its distribution cost by a demand ratchet. He explained that the demand ratchet sets each month at the highest demand for the following eleven months unless a higher kW of demand is recorded.[16]

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[14] *Id.* at 16-17.
[15] *Id.* at 18.
[16] *Id.* at 18-20.

The next change Mr. Bebyn proposed was to change the structure of charges for small demand ratepayers. He stated that currently all demand ratepayers are charged with a kW demand rate and a demand ratchet. Pascoag proposed that the General Service Demand < 200kW class have a kWh and ratchet kW component which will better align that classes' rates with usage. He proposed that the General Service Demand > 200kW continue with only a kW demand ratchet expressing concern that a change would create revenue instability due to the larger fluctuations in demand this group experiences.[17]

Mr. Bebyn's fourth change proposed eliminating seasonal rates and classifying customers in that group to the General Services Demand < 200kW that has both a kWh and ratchet kW component where the kWh will counterbalance the negative impact of having only a kW demand ratchet. Finally, he proposed that the Municipal Low Capacity Factor Rate have its own calculated rate that has a kWh and ratchet kW component. Mr. Bebyn described how he calculated and allocated the rates for the various classes. He also provided a list of the proposed updates to Pascoag's Terms and Conditions. The impact of the proposed rates on a typical residential customer using 500 kW per month is a 5.13% increase which equates to approximately $4 per month.[18]

III. The Settlement Agreement

On November 4, 2021, the Division of Public Utilities and Carriers (Division) filed a Settlement Agreement that reflected what the parties believed to be just and reasonable and in the public interest. The Settlement Agreement is attached as Appendix A. The Division represented that the terms of the Settlement Agreement state the position that it would have put forward had the Division filed direct testimony in the matter. The Settlement

[17] *Id.* at 20-21.
[18] *Id.* at 21-25.

Agreement provided for a reduction to the increase in distribution revenues initially sought by Pascoag from $379,332 to $340,484, a decrease of $38,848. The parties agreed to an increase of 4.24% over total rate year revenues. Discussed specifically in the Settlement Agreement was the parties' agreement to reduce Pascoag's request of $20,000 for Storm Contingency Adjustments to $12,000. The parties agreed that the Storm Contingency shall continue to remain as a stand-alone restricted account to be utilized only when the total incremental storm costs from a weather event exceed $4,000, subject to a $2,500 deductible, and shall only be used to pay for incremental storm costs. Should funds be used from the account, Pascoag shall notify the Division and the Commission within sixty days of the storm event causing the need to expend funds and provide an explanation of the event and a detailed accounting of what was charged.

In addition to a number of line-item adjustments that the parties agreed to, the Settlement Agreement specified that on a going forward basis, tree trimming functions would be outsourced. In order to resolve issues with Pascoag's net metering policy and how it was crediting customers, the parties agreed that by September 30, 2022, Pascoag shall install a two-meter net metering system that can independently record its existing net-metering customers' generation and usage. Also, all new customers participating in Pascoag's net metering program after January 1, 2022 will be required to install a two-meter net metering system at the customer's expense. Pascoag provided a revised net metering tariff outlining these details and included $1,100 in "Other Revenue" to reflect the impact of crediting customers the retail rate verses the blended rate as it had in the past due to its use of bi-directional meters. The Settlement Agreement provided that the debt service allowance of $113,600 will be restricted for the purpose of making payments on Pascoag's Rhode Island Infrastructure Bank loan. Regarding rate design, the parties agreed to employ gradualism in overall rate design. The specific terms are set forth in JS-17 which is attached to the Settlement Agreement.

IV. Hearing

On November 16, 2021, the Commission commenced a public comment and evidentiary hearing. No public comment was offered. During the evidentiary hearing, the Commission questioned Pascoag about its load. Mr. Kirkwood testified that there is still some uncertainty about Danielle Prosciutto International's (DPI) intentions to remain in its service territory but that the uncertainty is far less than in the past. He noted that DPI has made some capital improvements on their facilities, and while their load has diminished, it has stabilized. He indicated that he has less concern now than he did previously. He represented that Pascoag's overall load has remained flat and that he expects it to remain that way for the foreseeable future. Mr. Kirkwood explained Pascoag's rationale for outsourcing tree trimming noting that although Pascoag won't get 52 weeks a year of tree trimming, it will get very effective tree trimming with a contractor that Pascoag has experience with and that is more effective than the internal crew.[19]

Mr. Kirkwood testified that Pascoag intends to install new meters by the end of September 2022 for seven net metering customers who are currently being over-credited. He explained that new customers as of January 1, 2022 would be required to install a two-meter system at their own cost even though Pascoag's seven existing customers would have their meters replaced at no costs. He justified this by stating that Pascoag was assuming responsibility for not fully understanding how the current meters were reading the solar generation versus the load on the houses. He expressed that Pascoag needs time to ensure that replacement meters are installed in the correct format and consistent with the tariff,

[19] Hr'g Tr. at 18-25.

and that is the reason for the time difference between the new and existing net metering customer requirements. He noted that between engineering and ordering the new replacement meters for existing customers, especially now with supply chain issues, it will take time to accomplish the change to their existing systems and again stressed that he wants to make sure it is done right.[20]

Mr. Bebyn responded to questions regarding rate design. He explained the large increase in the non-LED street lighting class as Pascoag's attempt to encourage more customers to switch to LED lighting where that customer would experience a decrease in its rates. Mr. Kirkwood discussed Pascoag's capital plan and explained that it had begun to study the implementation of advance metering infrastructure (AMI) and how Pascoag was considering moving toward this technology. He testified that he attempts to keep up with changes in the industry and how he does not have instantaneous access to hourly data that would show him what each of the system's components, meters or transformers are registering. He stated that having this type of information provided by AMI would allow Pascoag to engage in more customer management on disconnects, reconnects, and outage management which he sees as the biggest benefit to an upgrade. He noted that since there are many different AMI technologies, Pascoag must first determine which technology would work best for its system and evaluate the cost. When asked if he planned to request Commission pre-approval for the project, he indicated that he had not, although if the costs exceeded what was allocated in Pascoag's capital budget, it would request some type of rate treatment.[21]

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[20] *Id.* at 27-32.
[21] *Id.* at 27, 33-45.

Mr. Kirkwood specified that in addition to being a regulated utility, Pascoag is under the jurisdiction of a Board that is elected by its customers which helps dictate the direction in which it proceeds. He stressed that his interest is making sure that the Commission is informed of what Pascoag is doing and is doing the right thing by its customers and good regulatory principles. His goal is to get the right functionality for the most efficient price. He stated that he wanted a system that provides robust functionality for future planning.[22]

Mr. Bebyn responded to questions regarding Pascoag's future capital spending. He explained that having a balance at the end of the year allows Pascoag the ability to commence a project the following year without waiting a full year to accumulate funds for the project. He noted that the balance also provides Pascoag with a cushion for unanticipated expenses. Mr. Kirkwood interjected that the fund also provides a cushion for emergency situations.[23]

Joel Munoz testified on behalf of the Division and in support of the Settlement Agreement. He testified that the Division found the funding level for Pascoag's capital spending to be reasonable. With regard to Pascoag's plans for AMI, Mr. Munoz stated that the Division wants to be included in conversations with Pascoag and wants to make sure that ratepayers are notified as well.[24]

DECISION

At an Open Meeting held on December 6, 2021, the PUC denied and dismissed Pascoag's General Rate Filing made on March 19, 2021 and unanimously voted to approve the Settlement Agreement filed by Pascoag and the Division on November 4, 2021. The rates set forth in the Settlement Agreement are approved for usage on and

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[22] *Id.* at 46-48.
[23] *Id.* at 48-53.
[24] *Id.* at 53-55.

after January 1, 2022. The Commission also approved Pascoag's Net Metering tariff, RIPUC No. 902. The Commission is satisfied that the Settlement Agreement between Pascoag and the Division is fair to and in the best interest of ratepayers and Pascoag.

The Commission also asked and, Pascoag agreed, to provide status reports on its study and plans for future implementation of AMI and to include in the status reports why replacement of the meters is needed in the time frame proposed. Although no schedule for the status reports was set, the Commission directed Pascoag to keep the Commission informed about its intentions and file formal updates when Pascoag has new information that is impacting its evaluation of the technology or is considering a material change in its approach. While the Commission made no decision regarding pre-approval, Pascoag should make timely updates which would provide the Commission with enough information to determine whether a pre-approval is warranted before Pascoag makes any material financial commitments.

ACCORDINGLY, it is hereby

(24315) ORDERED:

1. Pascoag Utility District's General Rate Filing made on March 19, 2021 is denied and dismissed.
2. The Settlement Agreement filed by Pascoag Utility District and the Division of Public Utilities and Carriers on November 4, 2021 is approved for usage on and after January 1, 2022.
3. Pascoag Utility District's Net Metering tariff (RIPUC No. 902) is approved.

EFFECTIVE AT WARWICK, RHODE ISLAND ON DECEMBER 6, 2021 PURSUANT TO AN OPEN MEETING DECISION ON DECEMBER 6, 2021. WRITTEN ORDER ISSUED ON JANUARY 21, 2022.

PUBLIC UTILITIES COMMISSION

Ronald T. Gerwatowski, Chairman

Abigail Anthony, Commissioner

John C. Revens, Jr., Commissioner

NOTICE OF RIGHT OF APPEAL: Pursuant to R.I. Gen. Laws §39-5-1, any person aggrieved by a decision or order of the PUC may, within seven days from the date of the order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or order.

APPENDIX A

STATE OF RHODE ISLAND

PUBLIC UTILITIES COMMISSION

IN RE: PASCOAG UTILITY DISTRICT APPLICATION TO CHANGE RATES	)))))	**DOCKET NO. 5134**

SETTLEMENT AGREEMENT

I. INTRODUCTION

This Settlement Agreement is entered into by and between Pascoag Utility District-Electric Department ("PUD" or "Pascoag") and the Division of Public Utilities and Carriers ("Division"), referred to collectively as the "Parties", in order to resolve the issues pending in the above-captioned proceeding. The Parties jointly request the Rhode Island Public Utilities Commission ("Commission")'s approval of this Settlement Agreement.

II. RECITALS

1. On March 19, 2021 the PUD filed with the Commission a Filing for Rate Change pursuant to R.I.G.L. §39-3-11.
2. In its filing, the PUD requested approval of new rates designed to collect additional revenues in the amount of $379,332 or 4.72% over total test-year revenues including pass through items of Last Resort Service and transmission revenues.
3. The filed adjusted test year total revenues were $8,038,936.
4. Adjusting out the pass-through revenue items totaling $5,286,265 resulted in test-year revenues of $2,752,671.
5. The filed demand/distribution revenue was kept at test-year levels.

6. The PUD filed testimony and supporting exhibits and schedules by Michael R. Kirkwood, PUD's General Manager, Harle Young, Manager, Finance and Customer Service and David Bebyn, C.P.A.
7. There are no Intervenors.
8. The Division thoroughly examined PUD's proposed rate changes.
9. The Division conducted discovery and reviewed PUD's responses to Commission discovery.
10. The Division performed an analysis of the proposed revenue request and engaged in settlement discussions with PUD. The Parties agreed to an increase of $340,484 or 4.24% in rate year revenues, a decrease of $37,390 from the requested $379,332.
11. After due consideration of the testimony, exhibits, data responses, and other documentation, the Parties believe that this settlement constitutes a just and reasonable resolution of the issues in this proceeding, is in the interests of ratepayers, and jointly request its approval by the Commission.

III. <u>TERMS OF SETTLEMENT</u>

Incorporated herein and attached hereto as *Exhibit 1* are Joint Settlement Schedules JS-1 through JS-17. The Parties agree with the accompanying schedules which reflect the following adjustments to the PUD's filed request:

A. <u>Storm Contingency Adjustments</u>

The Parties agree to reduce the amount the PUD requested for Storm Contingency Adjustments from $20,000 to $12,000, resulting in a decrease of $8,000, as shown on schedule JS-4. The balance in the storm reserve as of September 30, 2021 was approximately $111,000. In the PUD's last rate filing, Docket No. 4341, the target storm reserve level was set at $100,000.

In the current filing, the PUD seeks to build its storm reserve to $150,000. Both Parties agree that that the Storm Contingency will remain a stand-alone restricted account.

The Parties agree to utilize the storm reserve only when the total incremental storm costs from a weather event exceed $4,000, subject to a deductible of $2,500. The reserve shall only be used to pay for incremental storm costs. Pascoag will notify the Division and Commission within sixty days of a storm event that leads to the utilization of the storm reserve. The notification shall include a brief description of the event and an accounting of the amount charged against the Storm Contingency reserve that indicates the total storm costs and the application of the deductible.

B. PUC Assessment Fee Adjustment

The Parties agree to amend the PUC Assessment Fee as provided for in schedule JS-5 by using the most recent assessment, thereby decreasing the amount in the PUD's original filing from $39,210 to $37,491 resulting in a downward adjustment to the requested rate year revenues of $1,719.

C. Outsourcing of Tree Trimming Functions

The outsourcing of tree trimming function removes two positions from the PUD's full-time equivalent ("FTE") count thereby reducing labor and transportation expenses by $156,775 but also adds a contracted tree trimming expense for $155,000, resulting in a $1,775 downward adjustment to the requested rate year revenues, as shown in schedule JS-6.

D. Miscellaneous General Expenses

The Parties agree to: (i) normalize the $15,000 Battery Storage Impact Study over a three-year period as opposed to expensing all associated costs in one year; and (ii) eliminate one half of various other expenses in the Miscellaneous General Expenses account, resulting in a total downward adjustment to the requested rate year revenues of $14,484, as shown in schedule JS-7.

E. Usage of Test Year Amounts

The Parties agree to use the test year amounts for account numbers 593.130 (Over/Short Inventory Exp.), 923.004 (Outside Service-consulting), 935.000 (Maintenance of Plant), 930.200 (Safety Expense) as opposed to the three-year average that the PUD used in its original filing as shown in schedule JS-8. Nothing indicates that the test year recorded amounts for these accounts do not represent the current experience. The three-year averages include information from prior years that do not or will not necessarily apply currently or on a go-forward basis. This leads to an inability to determine a clear trend in the multi-year data that could be extrapolated into the Rate Year for these accounts. Due to the test year amounts accurate representation of the current experience for these four accounts, the Parties agree to use the Test Year recorded balances to determine the Rate Year revenue requirement. The use of the Test Year amounts results in a downward adjustment to the requested rate year revenues of $8,961.

F. Insurance Expense Adjustment

The Parties agree to use an asset-based allocation for components of insurance related to the value of property as provided for on Schedule DBG-RY-8. This adjustment decreases the amount for insurance expenses from $54,320 in the PUD's original filing to $49,243, and results in a downward adjustment of $5,077 to the requested rate year revenues, shown in schedule JS-9, p. 1.

G. Rate Case Expense

The Parties agree to amortize the rate case expense of $103,474 over a three-year period. Updating the rate case expense increases the annual amount by $5,825, as shown on Schedule JS-11.

H. Good Neighbor Energy Fund Sponsorship and Hosting

Each year PUD contributes $1,500 to the Good Neighbor Energy Fund and, approximately once every 3 years, hosts a breakfast at an expense of $4,500. The Parties agree to reduce the Good Neighbor Energy fund expense from $6,000 to $3,000 and amortize the PUD's hosting expense of $4,500 over a three-year period, as shown in schedule JS-12. The Company has a total amount of $6,000 in the rate year for account 923.006 – GNEF per Company schedule DGB-RY-3 resulting from already having $1,500 in the test year and adding $4,500 for the breakfast hosting. This adjustment reduces rate year expense by $3,000, based on reducing PUD's rate year expense amount of $6,000 to a $3,000 annual allowed amount.

I. Net Metering

PUD currently has seven residential net-metering customers on its system. Under Pascoag's tariff, generation from net-metering systems is credited at PUD's blended wholesale rate. Due to the PUD's use of bi-directional net meters to determine electricity generation and consumption, it cannot currently apply the "blended" wholesale rate to the amount credited by the PUD for electricity generated by a Customer-Generating facility, as required under its existing net metering policy.[1] This results in the crediting of customers at the full retail consumption rate. As the bi-directional net meters used by the existing net metering customers

[1] The Pascoag Utility District's existing net metering policy states, in relevant part, that " The amount credited by PUD for electricity produced by the Customer-Generating Facility shall be at PUD's "blended" wholesale rate, regardless of the type of generating facility." See Pascoag Utility District's Tariff as Authorized in Commission Order 20977, Docket No. 4341.

do not record generation and consumption amounts separately, the PUD is only capable of applying the retail rate to the electricity generated by the net metering customers, in contravention to the terms of the PUD's existing net metering policy.

To ensure that the existing net metering customers and the PUD have the ability to comply with the provisions of the PUD's net- metering tariff, the Parties agree that the PUD will install, at its own expense, two-meter net-metering systems that independently record existing net-metering customer's generation and usage. The installation of the two-meter system for the existing net-metering customers shall be completed no later than September 30, 2022. After January 1, 2022, all new customers participating in the PUD's net-metering program will be required to install a two-meter net-metering system, at the customer's expense, as required under the PUD's revised net-metering policy.

PUD estimated that the total annual impact of crediting the net-metering customers the retail rate verses the blended wholesale rate is $1,100. The Parties agree to include $1,100 as "Other Revenue" to prevent customer overpayment. In addition, the $1,100 represents the additional revenue Pascoag will receive when the existing net-metering customers transition to the two-meter system.

J. <u>Debt Service-Restricted Account</u>

In addition to the PUD's current restricted accounts (purchased power reserve, capital fund and storm contingency), the Parties agree that the debt service allowance of $113,600 will be restricted for the purpose of making payments on the PUD's existing Rhode Island Infrastructure Bank loan.

K. Rate Design

The Parties agree to the use of the rate classes, rates, base rate revenues, customer charges, and all other modifications as provided for in schedule JS-17.

The rate design proposed in PUD's original filing is based on its cost-of-service model. This proposal results in a wide range of increases and decreases among rate components. The Parties agreed to employ the concept of gradualism in overall rate design in order to avoid large increases and decreases in rates for any particular rate class. Additionally, the Parties agreed that, because this filing results in an overall increase in revenues, any rate component scheduled for a decrease is to be left unchanged and all other rates are to receive an increase based on the overall revenue requirement increase. Moreover, the Parties further agreed to apply this increase to non-LED streetlighting in order to encourage the conversion to LED street-lighting.

These changes result in the rates shown on Schedule JS-14 and the associated bill impacts shown on JS-15. The bill impact analysis shows that most customers would receive an increase of approximately 4%, General Service <200 KW class would receive an increase of 8%, and General Service >200 KW class would increase by 3%. Finally, the Parties agreed to modify this approach in an effort to moderate the impact on the General Service <200 KW class. An additional modification was calculated on Schedule JS-16 to shift some of the revenue requirements from the General Service <200 KW to the General Service >200 KW class. This modification helped flatten the total percentage impact of all the classes as presented on Schedule JS-17.

IV. ADDITIONAL TERMS OF SETTLEMENT

A. This Settlement Agreement is the product of negotiation and compromise and establishes no principles or precedents. The settlement discussions were conducted with the explicit understanding that all offers of settlement and discussion relating thereto are, and shall be, privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussion, and are not to be used in any manner in connection with these or any other proceedings.

B. The terms of this Settlement Agreement shall not be construed as an agreement to any matter of fact or law beyond the terms hereof. By entering into this Settlement Agreement, matters or issues other than those explicitly identified in this agreement have not been settled upon or conceded by any party to this Settlement Agreement, and nothing in this Settlement Agreement shall preclude any party from taking any position in any future proceeding regarding settled or unsettled matters.

C. The Commission's acceptance of this Settlement shall not in any respect bind the Commission on the merits of any issue in any subsequent rate proceeding.

D. In the event that the Commission (i) rejects this Settlement Agreement, (ii) fails to accept this Settlement Agreement as filed, or (iii) accepts this Settlement Agreement subject to conditions unacceptable to any party hereto, then this Settlement Agreement shall be deemed withdrawn and shall be null and void in all respects.

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AS WITNESS WHEREOF, the Parties agree that this Settlement Agreement is reasonable and have caused this document to be executed by their respective representatives, each being fully authorized to do so, on this ___ day of November 2021.

DIVISION OF PUBLIC UTILITIES AND CARRIERS
By its Attorney,

Mark Allen Simpkins, Esq. #9594
Deputy Chief of Legal Services
89 Jefferson Boulevard
Warwick, RI 02888
401-780-2146
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PASCOAG UTILITY DISTRICT
By its Attorney,

William L. Bernstein

William L. Bernstein, Esq. #2185
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EXHIBIT 1

Pascoag Utility District
Docket No. 5134
Settlement Schedules

CONTENTS

Pascoag Utility District

Summary of Revenue Requirement
Rate Year Ended June 30, 2022

		Per Pascoag						Per Settlement		
Line No.	Description	Test Year (A)	Adjustments (B)	Rate Year - Current Rates (C)	Revenue Requirement (D)	Rate Year - New Rates (E)		Rate Year - Current Rates (F)	Revenue Requirement (G)	Rate Year - New Rates (H)	Difference (I) = (G) - (D)
1	**Total Revenue**	$ 8,038,936	$ (5,286,265)	$ 2,752,671	$ 379,332	$ 3,132,003		$ 2,753,771	$ 340,484	$ 3,094,255	$ (38,848)
2	**Total Expenses**	$ 8,041,682	$ (4,955,965)	$ 3,085,717	$ -	$ 3,085,717		$ 3,048,527	$ -	$ 3,048,527	$ -
3	**Net Operating Income**	$ (2,746)	$ (330,301)	$ (333,046)	$ 379,332	$ 46,286	[A]	$ (294,756)	$ 340,484	$ 45,728	$ (38,848)
4	Percentage increase over TY Revenue (Including Fuel Revenue)			$ 379,332 /	$ 8,038,936 =	4.72%		$ 340,484 /	$ 8,038,936 =	4.24%	
5	Percentage increase over RY Revenue at Current Rates			$ 379,332 /	$ 2,752,671 =	13.78%		$ 340,484 /	$ 2,753,771 =	12.36%	

Notes and Source:
Cols. A-E: Schedule DGB-RY-1 from the Company's filing
Col. F: Schedule JS-2
Note [A]: 1.5 % of Expenses

Pascoag Utility District

Summary of Revenues and Expenses
Rate Year Ended June 30, 2022

Line No.	Acct. #	Budget Account Description	Per Pascoag: TY 2020 - Actual	Per Pascoag: Interim Year	Per Pascoag: Rate Year	Settlement Adjustment	Settled
			(A)	(B)	(C)	(D)	(E) = (C) + (D)
		REVENUE					
		Operating Revenue---Electricity Charges by Customer Class					
1	401-4401	Residential sales	$ -	$ -	$ -		$ -
2	401-4421	Commercial sales	$ -	$ -	$ -		$ -
3	401-4420	Industrial sales	$ -	$ -	$ -		$ -
4	401-4440	Public street lights	$ -	$ -	$ -		$ -
5	401-4441	Private street lights	$ -	$ -	$ -		$ -
6		*Total Operating Revenue---Electricity Charges by Customer Class*	$ -	$ -	$ -	$ -	$ -
		Operating Revenue---Pass Through					
7		Transmission	$ 1,988,469	$ 1,988,469	$ -		$ -
8		Transition	$ -	$ -	$ -		$ -
9		Standard Offer	$ 3,383,148	$ 3,383,148			$ -
10		PPRFC	$ (69,572)	$ (69,572)			$ -
11	407.040	Regulatory Credit-OC flow back	$ (15,780)	$ (15,780)			$ -
12	407.030	Regulatory Credit-PP Credit Refund	$ -	$ -	$ -		$ -
13		*Total Operating Revenue---Pass Through*	$ 5,286,265	$ 5,286,265	$ -	$ -	$ -
		Operating Revenue---Electricity Charge by Rate Class					
14		Demand/Distribution	$ 2,089,919	$ 2,089,919	$ 2,089,919		$ 2,089,919
15		Customer Chg	$ 489,630	$ 489,630	$ 489,630		$ 489,630
16		Public street lights	$ 43,872	$ 43,872	$ 43,872		$ 43,872
17		Private street lights	$ 29,459	$ 29,459	$ 29,459		$ 29,459
18		Power Factor Adjustment	$ (7,573)	$ (7,573)	$ (7,573)		$ (7,573)
19		*Total Operating Revenue---Electricity Charge by Rate Class*	$ 2,645,307	$ 2,645,307	$ 2,645,307	$ -	$ 2,645,307
		Other Revenue					
20	405-4190	Interest income	$ 6,746	$ 6,746	$ 6,746		$ 6,746
21	405-4220	Penalty interest	$ 23,038	$ 23,038	$ 23,038		$ 23,038
22	405-4210	Non-operating income	$ 3,190	$ 3,190	$ 3,190		$ 3,190
23	408-4510	Misc service revenue	$ -	$ -	$ -		$ -
24	408-4550	Other revenue/rent	$ 23,478	$ 23,478	$ 23,478		$ 23,478
25	408-4560	Other electric revenue	$ 29,131	$ 29,131	$ 29,131	1,100	$ 30,231
26	408-4570	Gain on sale of assets	$ 21,781	$ 21,781	$ 21,781		$ 21,781
27		*Total Other Revenue*	$ 107,364	$ 107,364	$ 107,364	$ 1,100	$ 108,464
28		TOTAL REVENUE	$ 8,038,936	$ 8,038,936	$ 2,752,671	$ 1,100	$ 2,753,771

Notes and Source:
Cols. A-C: Schedule DGB-RY-2 from the Company's filing

Summary of Revenues and Expenses
Rate Year Ended June 30, 2022

Line No.	Acct. #	Budget Account Description	Per Pascoag: Test Year - Adjusted (A)	Per Pascoag: Adjustments (B)	Per Pascoag: Rate Year - Adjusted (C)	Settlement Adjustments (D)	Settled (E) = (C) + (D)
		OPERATING EXPENSES					
1		*Operating Expense---Power Production*					
2	555.000	Purchased power	$ 3,733,562	$ (3,733,562)	$ -		$ -
3	555.500	Power supply expense	$ 2,340	$ (2,340)	$ -		$ -
4	565.000	Transmission	$ 1,550,363	$ (1,550,363)	$ -		$ -
5		*Total Operating Expense---Power Production*	$ 5,286,265	$ (5,286,265)	$ -	$ -	$ -
		Operating Expense---Distribution					
6	593.130	over/short inventory exp	$ 1,875	$ 1,089	$ 2,964	$ (1,089)	$ 1,875
7	580.000	Operation Supervisor	$ 99,887	$ 11,560	$ 111,447		$ 111,447
8	582.000	Operation supply & expense	$ 89,215	$ 120	$ 89,335		$ 89,335
9	586.000	O&M Meter expense	$ 47,839	$ 209	$ 48,048		$ 48,048
10	588.000	Misc distribution expense	$ 3,285	$ 349	$ 3,634		$ 3,634
11		*Total Operating Expense---Distribution*	$ 242,101	$ 13,327	$ 255,428	$ (1,089)	$ 254,339
		Operating Expense---Customer Service					
12	675.000	Misc. general	$ -	$ -	$ -		$ -
13	902.000	Customer meter reading	$ 8,499	$ 430	$ 8,929		$ 8,929
14	903.000	Customer record/collection	$ 214,267	$ 13,614	$ 227,881		$ 227,881
15	904.000	Uncollectible accounts	$ 44,172	$ (6,853)	$ 37,319		$ 37,319
16		*Total Operating Expense---Customer Service*	$ 266,938	$ 7,191	$ 274,129	$ -	$ 274,129
		Operating Expense---Administrative					
17	920.000	Admin general salaries	$ 452,327	$ 29,432	$ 481,759	$ (95,796)	$ 385,963
18	921.000	Office supplies and expense	$ 73,002	$ (4,364)	$ 68,638		$ 68,638
19	921.010	Custodial expense	$ 9,615	$ 7,272	$ 16,887		$ 16,887
20	922.000	Admin expense transfer	$ (124,410)	$ (3,012)	$ (127,422)		$ (127,422)
21	921.030	Dues and memberships	$ 11,492	$ -	$ 11,492		$ 11,492
22	923.000	Outside Service-legal	$ 19,843	$ 5,157	$ 25,000		$ 25,000
23	923.001	Outside Service-auditing	$ 29,043	$ 6,957	$ 36,000		$ 36,000
24	923.003	Outside Service-pension	$ 11,926	$ (1,883)	$ 10,043		$ 10,043
25	923.004	Outside Service-consulting	$ 13,540	$ 2,341	$ 15,881	$ (2,341)	$ 13,540
26	923.005	Outside Service-computer/IT	$ 102,327	$ 7,153	$ 109,480		$ 109,480
27	928.000	Rate Case	$ -	$ 28,667	$ 28,667	$ 5,825	$ 34,491
28	923.006	GNEF	$ 1,500	$ 4,500	$ 6,000	$ (3,000)	$ 3,000
29	924.000	Property insurance	$ 50,762	$ 3,558	$ 54,320	$ (5,077)	$ 49,243
30	925.000	Benefits/injuries & damages	$ 43,272	$ (15,218)	$ 28,054		$ 28,054
31	926.000	Benefits/Flex	$ 1,104	$ (1,104)	$ -		$ -
32	926.020	Employee Benefits-health	$ 190,341	$ 45,803	$ 236,144	$ (18,071)	$ 218,073
33	926.030	Schools & seminars	$ 41,400	$ (3,008)	$ 38,392		$ 38,392
34	926.040	Health Care - Others	$ 15,197	$ 1,268	$ 16,465		$ 16,465
35	926.005	DBP contributions	$ 127,306	$ 14,515	$ 141,821	$ (9,580)	$ 132,241
36	926.060	Employee benefits UHC-HRA	$ 7,398	$ -	$ 7,398		$ 7,398
37	933.000	Transportation	$ (5,057)	$ -	$ (5,057)	$ (26,000)	$ (31,057)
38	999-9999	Defined Benefit adjustment	$ -	$ -	$ -		$ -
39		*Total Operating Expense---Administrative*	$ 1,071,928	$ 128,034	$ 1,199,962	$ (154,040)	$ 1,045,922
40		*Total Operating Expenses*	$ 6,867,232	$ (5,137,713)	$ 1,729,519	$ (155,128)	$ 1,574,390
41		*Total Other Expenses*	$ 1,174,450	$ 181,749	$ 1,356,199	$ 117,938	$ 1,474,137
42		*Total Expenses*	$ 8,041,682	$ (4,955,965)	$ 3,085,717	$ (37,190)	$ 3,048,527

Notes and Source:
Cols. A-C: Schedule DGB-RY-3 from the Company's filing
Col. D: Schedule JS-3
Line 42: Schedule JS-2, Page 3, Line 32

Pascoag Utility District

Summary of Revenues and Expenses
Rate Year Ended June 30, 2022

Docket No. 5134
Schedule JS-2

Line No.	Acct. #	Budget Account Description	Per Pascoag Test Year - Adjusted (A)	Per Pascoag Adjustments (B)	Per Pascoag Rate Year - Adjusted (C)	Settlement Adjustments (D)	Settled (E) = (C) + (D)
		OTHER EXPENSES					
		Maintenance Expense---Distribution System					
1	585.000	Maint of street lights	$ 784	$ 716	$ 1,500		$ 1,500
2	584.000	Underground expense	$ -	$ -	$ -		$ -
3	592.000	Maint of station expense	$ 4,811	$ 5,689	$ 10,500		$ 10,500
4	592.100	Maint of structures	$ 5,934	$ 2,066	$ 8,000		$ 8,000
5	593.000	Overhead line expense	$ 373,739	$ 77,513	$ 451,252		$ 451,252
6	593.010	Contracted OH expense	$ 150,393	$ 17,735	$ 168,128	$ 155,000	$ 323,128
7	597.000	Maint of meters	$ -	$ 2,000	$ 2,000		$ 2,000
8		*Total Maintenance Expense---Distribution System*	$ 535,661	$ 105,719	$ 641,380	$ 155,000	$ 796,380
		Maintenance Expense---General					
9	930.230	Hazardous waste	$ 125	$ (83)	$ 42		$ 42
10		*Capitalized Labor*	$ 40,599	$ (40,599)	$ -		$ -
11		Future capital	$ 306,000	$ -	$ 306,000		$ 306,000
12		Storm Contingency	$ 20,000	$ -	$ 20,000	($8,000)	$ 12,000
13	935.000	Maint of plant	$ 33,863	$ 2,381	$ 36,244	$ (2,381)	$ 33,863
14		*Total Maintenance Expense---General*	$ 400,587	$ (38,301)	$ 362,286	$ (10,381)	$ 351,905
		Taxes					
15	408.000	Taxes - real estate	$ -	$ -	$ -		$ -
16	408.010	Taxes - employer FICA	$ 99,860	$ 2,732	$ 102,592	$ (7,328)	$ 95,264
17	408.020	Unemployment security	$ -	$ -	$ -		$ -
18		*Total Taxes*	$ 99,860	$ 2,732	$ 102,592	$ (7,328)	$ 95,264
		Depreciation					
19	403.000	Depreciation	$ -	$ -	$ -	$ -	$ -
20		*Total Depreciation*	$ -	$ -	$ -	$ -	$ -
		Other Deductions					
21	428.000	Amortization of debt acq	$ -	$ -	$ -		$ -
22	505-4270	LTD	$ -	$ 113,600	$ 113,600		$ 113,600
23	431.000	Other interest expense	$ 10,867	$ -	$ 10,867		$ 10,867
24		*Total Other Deductions*	$ 10,867	$ 113,600	$ 124,467	$ -	$ 124,467
		Misc. General					
25	930.100	General advertising	$ 976	$ (168)	$ 808		$ 808
26	930.200	Safety expense	$ 21,074	$ 3,150	$ 24,224	$ (3,150)	$ 21,074
27	930.210	Misc. general expense	$ 75,153	$ (5,113)	$ 70,040	($16,202)	$ 53,838
28	930.220	Donations	$ 520	$ 130	$ 650		$ 650
29	903.010	Billing expense	$ 29,752	$ -	$ 29,752		$ 29,752
30	930.250	Transfers	$ -	$ -	$ -		$ -
31		*Total Misc General*	$ 127,475	$ (2,001)	$ 125,474	$ (19,352)	$ 106,122
32		*Total Other Expenses*	$ 1,174,450	$ 181,749	$ 1,356,199	$ 117,938	$ 1,474,137

Notes and Source:
Cols. A-C: Schedule DGB-RY-3 from the Company's filing
Col. D: Schedule JS-3

Pascoag Utility District

Summary of Adjustments
Rate Year Ended June 30, 2022

Line No.	Description	Settlement Adjustments	Storm Contingency JS-4	PUC Assessment Fee JS-5	Outsourcing Tree Trimming Function Savings JS-6	Account No. 930.21 - Miscellaneous General Expenses JS-7	Usage of Test Year Amounts JS-8	Insurance Expense Adjustment JS-9	Avoid Subsidization by Other Customers of Over-Crediting for Net Metering JS-10	Rate Case Expense JS-11	GNEF Sponsorship and Hosting JS-12
	Revenue										
1	Operating Revenue---Electricity Charges by Customer Class	$ -									
2	Operating Revenue---Pass Through	-									
3	Operating Revenue---Electricity Charge by Rate Class	-									
4	Other Revenue	1,100							1,100		
5	Total Revenue	$ 1,100	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,100	$ -	$ -
	Expenses										
	Operations and Maintenance Expense										
6	Operating Expense---Power Production	$ -									
7	Operating Expense---Distribution	(1,089)					(1,089)				
8	Operating Expense---Customer Service	-									
9	Operating Expense---Administrative	(154,040)			(149,447)		(2,341)	(5,077)		5,825	(3,000)
10	Maintenance Expense---Distribution System	155,000			155,000						
11	Maintenance Expense---General	(10,381)	(8,000)				(2,381)				
12	Taxes	(7,328)			(7,328)						
13	Depreciation	-									
14	Other Deductions	-									
15	Misc. General	(19,352)		(1,719)		(14,484)	(3,150)				
16	Total Expenses	$ (37,190)	$ (8,000)	$ (1,719)	$ (1,775)	$ (14,484)	$ (8,961)	$ (5,077)	$ -	$ 5,825	$ (3,000)
17	Net Operating Income	$ 38,290	$ 8,000	$ 1,719	$ 1,775	$ 14,484	$ 8,961	$ 5,077	$ 1,100	$ (5,825)	$ 3,000

Pascoag Utility District

Storm Contingency
Rate Year Ended June 30, 2022

Line No	Description	Per Company (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	Adjustment to Storm Contingency	$20,000	$12,000	($8,000)

Notes and Source:
Col. A: Schedule DGB-RY-3 from the Company's filing

Pascoag Utility District

PUC Assessment Fee
Rate Year Ended June 30, 2022

Line No	Description	Per Company (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	Adjustment to PUC Assessment Fee	$39,210	$37,491	($1,719)

Notes and Source:
Col. A: Company response to DIV 1-7, Pascoag's General Ledger
Col. B: Company response to DIV 1-13 and DIV 3-1

Pascoag Utility District

Docket No. 5134
Schedule JS-6

Outsourcing Tree Trimming Function Savings
Rate Year Ended June 30, 2022

Line No.	Account No.	Description	Per Pascoag (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	920.000	Base Pay	$ 95,796	$ -	$ (95,796)
2	408.010	Payroll Taxes	$ 7,328	$ -	$ (7,328)
3	926.020	Employee Benefits	$ 18,071	$ -	$ (18,071)
4	926.005	Definited Benefit Program	$ 9,580	$ -	$ (9,580)
5	933.000	Transportation Expense Savings	$ 26,000	$ -	$ (26,000)
6	593.010	Contracted OH Expense (Tree Trimming Services)	$ -	$ 155,000	$ 155,000
7		Total	$ 156,775	$ 155,000	$ (1,775)

Notes and Source:
Col. A: Company response to Supplemental Comm 3-2
Line 6: per Settlement discussions

Pascoag Utility District

Docket No. 5134
Schedule JS-7

Account No. 930.21 - Miscellaneous General Expenses
Rate Year Ended June 30, 2022

Line No.	Date	Description	Per Pascoag (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	7/2/2019	flowers, PUC mtg, dunkin BUC mtg	$ 546.79	$ -	$ (546.79)
2	8/7/2019	ERP plan supplies, BUC mtg coffee	$ 57.11	$ -	$ (57.11)
3	9/6/2019	BJS REIMB HRU REIG, SPECIAL	$ 266.83	$ -	$ (266.83)
4	9/6/2019	FLOWERS FOR DOUG AND DENI	$ 112.00	$ -	$ (112.00)
5	9/10/2019	GREEN FESTIVAL RAFFLE DONA	$ 384.00	$ -	$ (384.00)
6	9/24/2019	BATTERY STORAGE IMPACT STU	$ 15,000.00	$ 5,000.00	$ (10,000.00)
7	10/1/2019	CORN STALKS AND MAP	$ 75.00	$ -	$ (75.00)
8	10/10/2019	COFFEE, GET WELL CARD, TABLE	$ 91.06	$ -	$ (91.06)
9	11/8/2019	code red mtg - lunch/coffee/wreaths for	$ 122.66	$ -	$ (122.66)
10	11/14/2019	deposit for catering	$ 100.00	$ -	$ (100.00)
11	12/12/2019	CHRISTMAS PARTY 2019	$ 1,815.90	$ -	$ (1,815.90)
12	12/12/2019	BKFST LINEMEN BRK, BJS REIMB	$ 454.71	$ -	$ (454.71)
13	12/19/2019	CHRISTMAS EVE BFAST 7103	$ 376.72	$ -	$ (376.72)
14	12/30/2019	PARKING, ANNUAL MTG FOOD, L	$ 92.96	$ -	$ (92.96)
15	1/23/2020	1/30/2020 LUNCH EVENT	$ 678.47	$ -	$ (678.47)
16	1/30/2020	PUD breakfast, com thank yous, neppa	$ 1,361.13	$ -	$ (1,361.13)
17	1/30/2020	retirement party supplies and gift	$ 867.00	$ -	$ (867.00)
18	1/30/2020	cake for morgan and tori	$ 16.99	$ -	$ (16.99)
19	2/21/2020	TABLE CLOTHES WASH AND DRY	$ 15.00	$ -	$ (15.00)
20	3/6/2020	BUC COFFEE, WATCHES, PRIME	$ 988.74	$ -	$ (988.74)
21	3/6/2020	PARKING DRY CLEAN TABLE CL	$ 79.69	$ -	$ (79.69)
22	4/13/2020	ERP SUPPLIES, COFFEE BUC MTG	$ 232.03	$ -	$ (232.03)
23	4/13/2020	PARKING, FOOD FOR it MTG	$ 28.97	$ -	$ (28.97)
24	5/4/2020	FOOD FOR ELEC OUTAGE	$ 71.50	$ -	$ (71.50)
25	5/29/2020	FLOWERS, LINDA AND GARY	$ 120.00	$ -	$ (120.00)
26	6/10/2020	phone stand	$ 12.38	$ -	$ (12.38)
27		Settlement allowance for half of other identified items		$ 4,484.00	$ 4,484.00
28		Adjustment to Miscellaneous General Expenses (Account No. 930.21)	$ 23,968	$ 9,484	$ (14,484)

Notes and Source:
Col. A: Company supplemental response to DIV 3-1c
Col. B, Line 6: Normalize Battery Storage Impact Study:

Battery Storage Impact Study	$ 15,000.00
Divide by 3 Years	3
Battery Storage Impact Study Amount in Rate Year	$ 5,000.00

Pascoag Utility District

Usage of Test Year Amounts
Rate Year Ended June 30, 2022

Line No.	Account No.	Description	Per Pascoag (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	593.130	Over/Short Inventory Exp	$ 2,964	$ 1,875	$ (1,089)
2	923.004	Outside Service-consulting	$ 15,881	$ 13,540	$ (2,341)
3	935.000	Maint of Plant	$ 36,244	$ 33,863	$ (2,381)
4	930.200	Safety Expense	$ 24,224	$ 21,074	$ (3,150)
		Total	$ 79,313	$ 70,352	$ (8,961)

Notes and Source:
Schedule DGB-TY-1, Schedule DGB-TY-2, and Schedule DGB-TY-3 from the Company's filing

Pascoag Utility District

Insurance Expense Adjustment
Rate Year Ended June 30, 2022

Line No.	Account No.	Description	Per Pascoag (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	924.000	Over/Short Inventory Exp	$ 54,320	$ 49,243	$ (5,077)
2		Total	$ 54,320	$ 49,243	$ (5,077)

Notes and Source:
Schedule DGB-RY-8, Settlement Position
Allocates cost for Commercial Property Insuance between electric and water utility operations using a fixed-asset based allocation

Pascoag Utility District

Insurance Expense Adjustment
Rate Year Ended June 30, 2022

Policy	2020 Term	Amount		2020 Electric (80%)	Water (20%)	
Insurances allocated with General Allocator Electric 80% Water 20%						
Excess Liability		$ 11,352		$ 9,082	$ 2,270	
General Liability		$ 10,129		$ 8,103	$ 2,026	
Auto Physical Damage		$ 4,847		$ 3,878	$ 969	
Auto Liability		$ 7,853		$ 6,282	$ 1,571	
Fiduciary		$ 3,000		$ 2,400	$ 600	
Public Officials		$ 5,302		$ 4,242	$ 1,060	
Premium Credit		$ (1,546)		$ (1,237)	$ (309)	
Crime		$ 2,926		$ 2,341	$ 585	
Contractor Equip-PERMA		$ 939		$ 751	$ 188	
Transportation Bond Starrkweather & Shepley		$ -		$ -	$ -	
Employment Practices/Purma Fees		$ 8,672		$ 6,938	$ 1,734	**Due July**
ERISA (3Year Policy Pd in 2020 $412)		$ 412		$ 330	$ 82	
PURMA Fee		$ -		$ -	$ -	
Annual Dues		$ 1,300		$ 1,040	$ 260	
Insurances allocated with net Fixed Assets Electric 29% Water 71% (Response to DIV 3-9d)						
Commercial Property		$ 9,481		$ 2,749	$ 6,732	
Interim Year	5%	**$ 64,667**	**	$ 46,898	$ 17,769	**$ 64,667**
	Average yearly increase	5%				
Rate Year		$ 67,900		$ 49,243	$ 18,657	**$ 67,900**

Test Year 924.000 Property Insurance	$	50,762
Rate Year 924.000 Property Insurance	$	49,243
Rate Year Adjustment	$	(1,519)

Notes and Source:
Pascoag Schedule DGB-RY-8, Settlement Position

Pascoag Utility District

Docket No. 5134
Schedule JS-10

Avoid Subsidization by Other Customers of Over-Crediting for Net Metering
Rate Year Ended June 30, 2022

Line No.	Account No.	Description	Per Pascoag (A)	Settlement Adjustment (B)	Settled (C) = (B) - (A)
1	408-4560	Other Revenue	$ -	$ 1,100	$ 1,100
2		Total	$ -	$ 1,100	$ 1,100

Notes and Source:

Add approximate amount of annual over-crediting to Other Revenue to avoid having other customers subsidize Pascoag's over-crediting to seven current net-metering customers.

Pascoag Utility District

Rate Case Expense
Rate Year Ended June 30, 2022

Line No.	Description	Original Estimate (A)	11/1/21 Estimate (B)	Settlement Adjustment (C) = (B) - (A)
1	Division	$ 40,000	$ 40,000	$ -
2	B&E Consulting	$ 40,000	$ 53,375	$ 13,375
3	Legal - Pascoag	$ 4,700	$ 8,799	$ 4,099
4	Notices	$ 1,000	$ 1,000	$ -
5	Printer	$ 300	$ 300	$ -
6	Total Rate Case Expense	$ 86,000	$ 103,474	$ 17,474
7	Amortize over 3 Years	3	3	
8	Adjustment to Rate Case Expense	$ 28,667	$ 34,491	$ 5,825

Notes and Source:
Col. A: Schedule DGB-RY-10 from the Company's filing
Col. B: Rate Case Expense amount agreed upon by the Parties

Pascoag Utility District

GNEF Sponsorship and Hosting
Rate Year Ended June 30, 2022

Line No.	Description	Per Company (A)	Allowance (B)	Settlement Adjustment (C) = (B) - (A)
1	Adjustment to GNEF Sponsorship and Hosting	$ 6,000	$ 3,000	$ (3,000)

Notes and Source:

Col. A: Company witness David G. Bebyn Direct Testimony, page 13 and Company Schedule DGB-RY-3
Col. B: Allowance amount agreed upon by the Parties

Pascoag Utility District

Cost of Service Allocation
Rate Year Ended June 30, 2022

Line No.	Acct. #	Budget Account Description	Settled Adjusted Rate Year (A)	Allocator (B)	Production/ Purchase (C)	Transmission (D)	Demand/ Distribution (E)	Street Lighting (F)	Customer Service (G)
		EXPENSES							
		Operating Expense---Power Production							
1	555.000	Purchased power	$ -	P	$ -	$ -	$ -	$ -	$ -
2		Purchased power - Street Light	$ -	SL-P	$ -	$ -	$ (37,736)	$ 37,736	$ -
3	555.500	Power supply expense	$ -	P	$ -	$ -	$ -	$ -	$ -
4	565.000	Transmission	$ -	P	$ -	$ -	$ -	$ -	$ -
5		*Total Operating Expense---Power Production*	$ -		$ -	$ -	$ (37,736)	$ 37,736	$ -
		Operating Expense---Distribution							
6	593.130	over/short inventory exp	$ 1,875	D	$ -	$ -	$ 1,875		$ -
7	580.000	Operation Supervisor	$ 111,447	D	$ -	$ -	$ 111,447	$ -	$ -
8	582.000	Operation supply & expense	$ 89,335	DSL	$ -	$ -	$ 80,402	$ 8,934	$ -
9	586.000	O&M Meter expense	$ 48,048	C	$ -	$ -	$ -	$ -	$ 48,048
10	588.000	Misc distribution expense	$ 3,634	D	$ -	$ -	$ 3,634	$ -	$ -
11		*Total Operating Expense---Distribution*	$ 254,339		$ -	$ -	$ 197,358	$ 8,934	$ 48,048
		Operating Expense---Customer Service							
12	675.000	Misc general	$ -	C	$ -	$ -	$ -	$ -	$ -
13	902.000	Customer meter reading	$ 8,929	C	$ -	$ -	$ -	$ -	$ 8,929
14	903.000	Customer record/collection	$ 227,881	C	$ -	$ -	$ -	$ -	$ 227,881
15	904.000	Uncollectible accounts	$ 37,319	G	$ -	$ -	$ 31,869	$ 688	$ 4,762
16		*Total Operating Expense---Customer Service*	$ 274,129		$ -	$ -	$ 31,869	$ 688	$ 241,572
		Operating Expense---Administrative							
17	920.000	Admin general salaries	$ 385,963	D	$ -	$ -	$ 385,963	$ -	$ -
18	921.000	Office supplies and expense	$ 68,638	G	$ -	$ -	$ 58,615	$ 1,264	$ 8,758
19	921.010	Custodial expense	$ 16,887	G	$ -	$ -	$ 14,421	$ 311	$ 2,155
20	922.000	Admin expense transfer	$ (127,422)	A	$ -	$ -	$ (77,727)	$ (1,274)	$ (48,420)
21	921.030	Dues and memberships	$ 11,492	G	$ -	$ -	$ 9,814	$ 212	$ 1,466
22	923.000	Outside Service-legal	$ 25,000	G	$ -	$ -	$ 21,349	$ 461	$ 3,190
23	923.001	Outside Service-auditing	$ 36,000	G	$ -	$ -	$ 30,743	$ 663	$ 4,594
24	923.003	Outside Service-pension	$ 10,043	Pr	$ -	$ -	$ 8,380	$ 201	$ 1,463
25	923.004	Outside Service-consulting	$ 13,540	G	$ -	$ -	$ 11,563	$ 249	$ 1,728
26	923.005	Outside Service-computer/IT	$ 109,480	G	$ -	$ -	$ 93,493	$ 2,017	$ 13,970
27	928.000	Rate Case	$ 34,491	G	$ -	$ -	$ 29,455	$ 635	$ 4,401
28	923.006	GNEF	$ 3,000	D	$ -	$ -	$ 3,000	$ -	$ -
29	924.000	Property insurance	$ 49,243	D	$ -	$ -	$ 49,243	$ -	$ -
30	925.000	Benefits/injuries & damages	$ 28,054	Pr	$ -	$ -	$ 23,407	$ 561	$ 4,086
31	926.000	Benefits/Flex	$ -	Pr	$ -	$ -	$ -	$ -	$ -
32	926.020	Employee Benefits-health	$ 218,073	Pr	$ -	$ -	$ 181,951	$ 4,361	$ 31,761
33	926.030	Schools & seminars	$ 38,392	G	$ -	$ -	$ 32,786	$ 707	$ 4,899
34	926.040	Health Care - Others	$ 16,465	G	$ -	$ -	$ 14,061	$ 303	$ 2,101
35	926.005	DBP contributions	$ 132,241	Pr	$ -	$ -	$ 110,337	$ 2,645	$ 19,260
36	926.060	Employee benefits UHC-HRA	$ 7,398	Pr	$ -	$ -	$ 6,173	$ 148	$ 1,077
37	933.000	Transportation	$ (31,057)	G	$ -	$ -	$ (26,522)	$ (572)	$ (3,963)
38	999-9999	DB adjustment	$ -	G	$ -	$ -	$ -	$ -	$ -
39		*Total Operating Expense---Administrative*	$ 1,045,922		$ -	$ -	$ 980,503	$ 12,893	$ 52,525
		Maintenance Expense---Distribution System							
40	585.000	Maint of street lights	$ 1,500	D	$ -	$ -	$ -	$ 1,500	$ -
41	584.000	Underground expense	$ -	D	$ -	$ -	$ -	$ -	$ -
42	592.000	Maint of station expense	$ 10,500	D	$ -	$ -	$ 10,500	$ -	$ -
43	592.100	Maint of structures	$ 8,000	D	$ -	$ -	$ 8,000	$ -	$ -
44	593.000	Overhead line expense	$ 451,252	D	$ -	$ -	$ 451,252	$ -	$ -
45	593.010	Contracted OH expense	$ 323,128	D	$ -	$ -	$ 323,128	$ -	$ -
46	597.000	Maint of meters	$ 2,000	D	$ -	$ -	$ 2,000	$ -	$ -
47		*Total Maintenance Expense---Distribution System*	$ 796,380		$ -	$ -	$ 794,880	$ 1,500	$ -
		Maintenance Expense---General							
48	930.230	Hazardous waste	$ 42	D	$ -	$ -	$ 42	$ -	$ -
49		*Capitalized Labor*	$ -	D	$ -	$ -	$ -	$ -	$ -
50		Future capital	$ 306,000	D	$ -	$ -	$ 306,000	$ -	$ -
51		Storm Contingency	$ 12,000	D	$ -	$ -	$ 12,000	$ -	$ -
52	935.000	Maint of plant	$ 33,863	D	$ -	$ -	$ 33,863	$ -	$ -
53		*Total Maintenance Expense---General*	$ 351,905		$ -	$ -	$ 351,905	$ -	$ -
		Taxes							
54	408.000	Taxes - real estate	$ -	C	$ -	$ -	$ -	$ -	$ -
55	408.010	Taxes - employer FICA	$ 95,264	Pr	$ -	$ -	$ 79,484	$ 1,905	$ 13,874
56	408.020	Unemployment security	$ -	Pr	$ -	$ -	$ -	$ -	$ -
57		*Total Taxes*	$ 95,264		$ -	$ -	$ 79,484	$ 1,905	$ 13,874
		Depreciation							
58	403.000	Depreciation	$ -	D	$ -	$ -	$ -	$ -	$ -
59		*Total Depreciation*	$ -		$ -	$ -	$ -	$ -	$ -
		Other Deductions							
60	428.000	Amortization of debt acq	$ -	D	$ -	$ -	$ -	$ -	$ -
61	505-4270	Interest on LTD	$ 113,600	D	$ -	$ -	$ 113,600	$ -	$ -
62	431.000	Other interest expense	$ 10,867	D	$ -	$ -	$ 10,867	$ -	$ -
63		*Total Other Deductions*	$ 124,467		$ -	$ -	$ 124,467	$ -	$ -
		Misc. General							
64	930.100	General advertising	$ 808	G	$ -	$ -	$ 690	$ 15	$ 103
65	930.200	Safety expense	$ 21,074	D	$ -	$ -	$ 21,074	$ -	$ -
66	930.210	Misc. general expense	$ 53,838	D	$ -	$ -	$ 53,838	$ -	$ -
67	930.220	Donations	$ 650	G	$ -	$ -	$ 555	$ 12	$ 83
68	903.010	Billing expense	$ 29,752	C	$ -	$ -	$ -	$ -	$ 29,752
69	930.250	Transfers	$ -	C	$ -	$ -	$ -	$ -	$ -
70		*Total Misc General*	$ 106,122		$ -	$ -	$ 76,157	$ 27	$ 29,938
71		***TOTAL EXPENSES***	$ 3,048,527	R	$ -	$ -	$ 2,598,887	$ 63,682	$ 385,958
72		Net Operating Income	$ 45,728	R	$ -	$ -	$ 35,668	$ 1,372	$ 8,688
73		Power Factor Adjustment	$ (7,573)	R	$ -	$ -	$ (5,907)	$ (227)	$ (1,439)
74		Total Other Revenue	$ 108,464	R	$ -	$ -	$ 84,602	$ 3,254	$ 20,608
75		**Net Revenue Requirement**	$ 2,993,364		$ -	$ -	$ 2,555,859	$ 62,028	$ 375,477

Notes and Source:
Col. A: Schedule JS-2
Col. B and Line 2: Schedule DGB-COS-1 from Pascoag's filing
Cols. C-G: Based on Allocation Factors shown in Schedule JS-4, Page 2
Lines 2 and 40: Company response to DIV 4-6, Attachment DIV 4-6

Pascoag Utility District

Cost of Service Allocation Factors
Rate Year Ended June 30, 2022

Description	Allocator	Production/ Purchase	Transmission	Demand/ Distribution	Street Lighting	Customer Service
Power Purchase	P	100%	0%	0%	0%	0%
Transmission	T	0%	100%	0%	0%	0%
Demand/Distribution	D	0%	0%	100%	0%	0%
Distribution SL Overhead	DSL	0%	0%	90%	10%	0%
Street light - Maintenance	SL	0%	0%	0%	100%	0%
Stree light - power	SL-P	This allocator recovers the amount of power used by and provides an offset to other electric customers				
Customer service	C	0%	0%	0%	0%	100%
General Allocator	G	0%	0%	85%	2%	13%
Payroll -Related	Pr	0%	0%	83%	2%	15%
Admin Transfer	A	0%	0%	61%	1%	38%
Revenue	R	0%	0%	78%	3%	19%

Notes and Source:
Schedule DGB-COS-2 from Pascoag filing

Rate Design - Proof
Rate Year Ended June 30, 2022

	Count or Usage	Current		Settled Rate	Current Revenue	Pascoag Proposed Revenue	Settled Revenue	Revenue at New Rates	Pascoag Dollar Increase/(Decrease)	Settled Dollar Increase/(Decrease)	Pascoag Percent Increase/(Decrease)	Settled Percent Increase/(Decrease)
	(A)	(B)		(C) = F / A	(D)	(E)	(F)	(F1) = A x C	(G) = (E) - (D)	(H) = (F) - (D)	(I) = (G) / (D)	(J) = (H) / (D)
Demand/Distribution Rates				Calculate to roughly same overall % increase		Amount to be allocated:	$ 2,440,383				Division has concer about wide % swings	
Residential (A) - per kWh	32,414,464	$ 0.03922		$ 0.04558	$ 1,271,295	$ 1,582,886	$ 1,477,357	$ 1,477,357	$ 311,591	$ 206,062	24.51%	16.21%
Commercial (B) - kWh	3,321,658	$ 0.04196		$ 0.04876	$ 139,377	$ 153,322	$ 161,968	$ 161,968	$ 13,945	$ 22,591	10.01%	16.21%
General Service MLCFR - per kWh	29,089	$ -		$ 0.13185	$ -	$ 2,330	$ 3,835	$ 3,835	$ 2,330	$ 3,835		
General Service MLCFR - per kW	644	$ 10.25		$ 5.96	$ 6,601	$ 2,330	$ 3,835	$ 3,835	$ (4,271)	$ (2,766)	-29.40%	16.21%
General Service <200 KW - per kWh	8,729,450	$ -		$ 0.02428	$ -	$ 210,420	$ 211,948	$ 211,948	$ 210,420	$ 211,948		
General Service <200 KW - per kW	35,587	$ 10.25		$ 5.96	$ 364,771	$ 210,420	$ 211,948	$ 211,948	$ (154,351)	$ (152,823)	15.37%	16.21%
General Service >200 KW	30,037	$ 10.25		$ 11.91	$ 307,879	$ 422,364	$ 357,782	$ 357,782	$ 114,485	$ 49,904	37.19%	16.21%
					$ 2,089,923	$ 2,584,070	$ 2,428,675	$ 2,428,675	$ 494,150	$ 338,752	23.64%	16.21%
Customer Charge (per month rate)				Hold to Current								Hold to Current
Residential (A)	51,372	$ 6.00	$ -	$ 6.00	$ 308,232	$ 256,860	$ 308,232	$ 308,232	$ (51,372)	$ -	-16.67%	0.00%
Commercial (B)	6,384	$ 15.00	$ -	$ 15.00	$ 95,760	$ 81,396	$ 95,760	$ 95,760	$ (14,364)	$ -	-15.00%	0.00%
General Service MLCFR - per kW	24	$ 112.75		$ 112.75	$ 2,706	$ 1,272	$ 2,706	$ 2,706	$ (1,434)	$ -	-52.99%	0.00%
General Service <200 KW - per kWh	648	$ 112.75		$ 112.75	$ 73,062	$ 34,344	$ 73,062	$ 73,062	$ (38,718)	$ -	-52.99%	0.00%
General Service >200 KW	72	$ 112.75	$ -	$ 112.75	$ 8,118	$ 6,840	$ 8,118	$ 8,118	$ (1,278)	$ -	-15.74%	0.00%
					$ 487,878	$ 380,712	$ 487,878	$ 487,878	$ (107,166)	$ -		
Street Lighting (per month rate)				Increase Non-LED by Overall Increase				LED by Overall Increase			Wide swings in PUD proposed	Increase Non-LED by Overall Increase
175 Watt Mercury	144	$ 8.47	$ -	$ 9.84	$ 1,220	$ 1,223	$ 1,417	$ 1,417	$ 4	$ 198	0.35%	16.21%
	-											
50 Watt Sodium	528	$ 4.58	$ -	$ 5.32	$ 2,418	$ 1,886	$ 2,810	$ 2,810	$ (532)	$ 392	-22.01%	16.21%
70 Watt Sodium	120	$ 5.20	$ -	$ 6.04	$ 624	$ 522	$ 725	$ 725	$ (102)	$ 101	-16.35%	16.21%
100 Watt Sodium	48	$ 6.37	$ -	$ 7.40	$ 306	$ 280	$ 355	$ 355	$ (25)	$ 50	-8.10%	16.21%
150 Watt Sodium	96	$ 8.13	$ -	$ 9.45	$ 780	$ 775	$ 907	$ 907	$ (6)	$ 127	-0.83%	16.21%
250 Watt Sodium	588	$ 10.96	$ -	$ 12.74	$ 6,444	$ 6,849	$ 7,489	$ 7,489	$ 404	$ 1,045	6.26%	16.21%
400 Watt Sodium	372	$ 15.74	$ -	$ 18.29	$ 5,855	$ 6,586	$ 6,804	$ 6,804	$ 730	$ 949	12.46%	16.21%
				Hold LED Street Lighting to Current				Hold LED to Current				Held to Current Rates in this proposal
25W LED/ 2,188 Lumens	9,840	$ 2.87	$ -	$ 2.87	$ 28,241	$ 22,401	$ 28,241	$ 28,241	$ (5,840)	$ -	-20.68%	0.00%
50W LED/ 3,956 Lumens	2,280	$ 3.71	$ -	$ 3.71	$ 8,459	$ 7,116	$ 8,459	$ 8,459	$ (1,342)	$ -	-15.86%	0.00%
120W LED/ 11,730 Lumens	996	$ 8.13	$ -	$ 8.13	$ 8,097	$ 6,896	$ 8,097	$ 8,097	$ (1,202)	$ -	-14.85%	0.00%
240W LED/ 22,797 Lumens	588	$ 12.73	$ -	$ 12.73	$ 7,485	$ 6,664	$ 7,485	$ 7,485	$ (821)	$ -	-10.97%	0.00%
73W LED Decrotive with pole	468	$ 8.59	$ -	$ 8.59	$ 4,020	$ 3,182	$ 4,020	$ 4,020	$ (838)	$ -	-20.85%	0.00%
					$ 73,950	$ 64,380	$ 76,811	$ 76,811	$ (9,571)	$ 2,861		
Power Factor Adjustment					$ (7,573)	$ (7,573)	$ (7,573)	$ (7,573)	$ (7,573)	$ -		
											Diff: Divison less Pascoag	
Total Rates and Charges					$ 2,644,178	$ 3,021,591	$ 2,985,790	$ 2,985,790	$ 377,413	$ 341,613	$ (35,801)	
Total Other Revenue (Schedule JS-2, Page 1), add $1,100 to Other Revenue for Net Metering credit issue					$ 107,364	$ 107,364	$ 108,464	$ 108,464	$ 107,364	$ 108,464	$ 1,100	
TOTAL REVENUE					$ 2,751,542	$ 3,128,955	$ 3,094,254	$ 3,094,254	$ 484,777	$ 450,077	$ (34,701)	

		Current	Pascoag	Division/Settlement		Diff Divisions vs PUD	
Total Expenses	JS-1, line 2	$ 3,085,717	$ 3,085,717	$ **3,048,527**		$ (37,190)	
Net Operating Income	JS-1, line 3	$ (333,046)	$ 46,286	$ **45,728**		$ (558)	
Power Factor Adjustment	JS-2, page 1, line 18		$ 7,573	$ 7,573		$ -	
Total Other Income	JS-2, page 1, line 27		$ (107,364)	$ (108,464)		$ (1,100)	
Total Net Revenue Requirement (Sch DGB-COS-1, page 2)		$ 2,752,671	$ 3,032,212	$ 2,993,364		$ (38,848)	Difference, JS-1, column I, line 1
Power Factor Adjustment			$ (7,573)	$ (7,573)		$ -	
Total Other Income			$ 107,364	$ 108,464		$ 1,100	
Net Revenue Required (calculated from above)	JS-1, line 1, col. E and H		$ 3,132,003	$ 3,094,255	3,094,255	$ (37,748)	
Net Revenue Required (Schedule JS-1)			$ 3,128,955	$ 3,094,254	$ 3,094,254	$ (34,701)	
Difference			$ 3,048	$ 1	$ 1	$ (3,047)	

Pascoag Utility District

Rate Design - Impact
Rate Year Ended June 30, 2022

	Usage (kWh)	Usage (kW)		Current Rate	Proposed Rate	Current Revenue	Proposed Revenue	Current Revenue	Proposed Revenue	Dollar Increase	% Increase
Residential (A)											
	300		DIS-kWh	$ 0.03922	$ 0.04558	$ 11.77	$ 13.67	$ 47.95	$ 49.86	$ 2	3.98%
	300		PT	$ 0.10062	$ 0.10062	$ 30.19	$ 30.19				
			CS	$ 6.00	$ 6.00	$ 6.00	$ 6.00				
	500			$ 0.03922	$ 0.04558	$ 19.61	$ 22.79	$ 75.92	$ 79.10	$ 3	4.19%
	500			$ 0.10062	$ 0.10062	$ 50.31	$ 50.31				
				$ 6.00000	$ 6.00000	$ 6.00	$ 6.00				
	1000			$ 0.03922	$ 0.04558	$ 39.22	$ 45.58	$ 145.84	$ 152.20	$ 6	4.36%
	1000			$ 0.10062	$ 0.10062	$ 100.62	$ 100.62				
				$ 6.00000	$ 6.00000	$ 6.00	$ 6.00				
	2,000			$ 0.03922	$ 0.04558	$ 78.44	$ 91.15	$ 285.68	$ 298.39	$ 13	4.45%
	2,000			$ 0.10062	$ 0.10062	$ 201.24	$ 201.24				
				$ 6.00000	$ 6.00000	$ 6.00	$ 6.00				
Commercial (B)											
	500		DIS-kWh	$ 0.04196	$ 0.04876	$ 20.98	$ 24.38	$ 86.29	$ 89.69	$ 3	3.94%
	500		PT	$ 0.10062	$ 0.10062	$ 50.31	$ 50.31				
			CS	$ 15.00	$ 15.00	$ 15.00	$ 15.00				
	800			$ 0.04196	$ 0.04876	$ 33.57	$ 39.01	$ 129.06	$ 134.50	$ 5	4.22%
	800			$ 0.10062	$ 0.10062	$ 80.50	$ 80.50				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
	1000			$ 0.04196	$ 0.04876	$ 41.96	$ 48.76	$ 157.58	$ 164.38	$ 7	4.32%
	1000			$ 0.10062	$ 0.10062	$ 100.62	$ 100.62				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
	3,000			$ 0.04196	$ 0.04876	$ 125.88	$ 146.28	$ 442.74	$ 463.14	$ 20	4.61%
	3,000			$ 0.10062	$ 0.10062	$ 301.86	$ 301.86				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
	5,000			$ 0.04196	$ 0.04876	$ 209.80	$ 243.81	$ 727.90	$ 761.91	$ 34	4.67%
	5,000			$ 0.10062	$ 0.10062	$ 503.10	$ 503.10				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
General Service <200 KW											
		18	DIS-KW	$ 10.25	$ 5.956	$ 184.50	$ 107.20	$ 911.43	$ 982.34	$ 71	7.78%
	6,104		DIS-kWh	$ -	$ 0.02428	$ -	$ 148.20				
	6,104		PT	$ 0.10062	$ 0.10062	$ 614.18	$ 614.18				
			CS	$ 112.75	$ 112.75	$ 112.75	$ 112.75				
		53		$ 10.25000	$ 5.95570	$ 543.25	$ 315.65	$ 2,259.18	$ 2,418.43	$ 159	7.05%
	15,933			$ -	$ 0.02428	$ -	$ 386.85				
	15,933			$ 0.10062	$ 0.10062	$ 1,603.18	$ 1,603.18				
				$ 112.750	$ 112.750	$ 112.75	$ 112.75				
		105		$ 10.25000	$ 5.95570	$ 1,076.25	$ 625.35	$ 4,729.52	$ 5,132.94	$ 403	8.53%
	35,187			$ -	$ 0.02428	$ -	$ 854.33				
	35,187			$ 0.10062	$ 0.10062	$ 3,540.52	$ 3,540.52				
				$ 112.75000	$ 112.75000	$ 112.75	$ 112.75				
General Service >200 KW											
		350	DIS-KW	$ 10.25000	$ 11.91141	$ 3,587.50	$ 4,168.99	$ 20,302.55	$ 20,884.04	$ 581	2.86%
	165,000		PT	$ 0.10062	$ 0.10062	$ 16,602.30	$ 16,602.30				
			CS	$ 112.75000	$ 112.75000	$ 112.75	$ 112.75				
		620		$ 10.25000	$ 11.91141	$ 6,355.00	$ 7,385.07	$ 28,604.15	$ 29,634.22	$ 1,030	3.60%
	220,000			$ 0.10062	$ 0.10062	$ 22,136.40	$ 22,136.40				
				$ 112.75000	$ 112.75000	$ 112.75	$ 112.75				

	(A)	*	
Percentage increase over TY Revenue (Including Pass-thru Revenue) - Schedule JS-1	$ 341,584 /	$ 8,038,936	4.25%
Percentage increase over RY Revenue at Current Rates - Schedule J-1	341,584 /	2,752,671	12.41%

	Sch JS-14 Settlement Total Revenue		*		
(A)	$3,094,254	-	$2,752,671	=	$341,583

Notes and Source:
* Schedule DGB-RD-4 from the Company's filing

Pascoag Utility District

Rate Design with Gradualism - Proof
Rate Year Ended June 30, 2022

	Count or Usage	Current		Settled Rate	Current Revenue	Pascoag Proposed Revenue	**Gradualism Settled Revenue**	Revenue at New Rates	Pascoag Dollar Increase/(Decrease)	Settled Dollar Increase/(Decrease)	Pascoag Percent Increase/(Decrease)	Settled Percent Increase/(Decrease)
	(A)	(B)		(C) = F / A	(D)	(E)	(F)	(F1) = A x C	(G) = (E) - (D)	(H) = (F) - (D)	(I) = (G) / (D)	(J) = (H) / (D)
Demand/Distribution Rates				Calculate to roughly same overall % increase		Amount to be allocated:	$ 2,440,383				Division has concer about wide % swings	
Residential (A) - per kWh	32,414,464	$ 0.03922		$ 0.04558	$ 1,271,295	$ 1,582,886	$ 1,477,357	$ 1,477,357	$ 311,591	$ 206,062	24.51%	16.21%
Commercial (B) - kWh	3,321,658	$ 0.04196		$ 0.04876	$ 139,377	$ 153,322	$ 161,968	$ 161,968	$ 13,945	$ 22,591	10.01%	16.21%
General Service MLCFR - per kWh	29,089	$ -		$ 0.13185	$ -	$ 2,330	$ 3,835	$ 3,835	$ 2,330	$ 3,835		
General Service MLCFR - per kW	644	$ 10.25		$ 5.96	$ 6,601	$ 2,330	$ 3,835	$ 3,835	$ (4,271)	$ (2,766)	-29.40%	16.21%
General Service <200 KW - per kWh	8,729,450	$ -		$ **0.02428**	$ -	$ 210,420	$ **211,948**	$ 211,948	$ 210,420	$ 211,948		
General Service <200 KW - per kW	35,587	$ 10.25		$ **5.11**	$ 364,771	$ 210,420	$ **181,948**	$ 181,948	$ (154,351)	$ (182,823)	15.37%	7.98%
General Service >200 KW	30,037	$ 10.25		$ **12.91**	$ 307,879	$ 422,364	$ **387,782**	$ 387,782	$ 114,485	$ 79,904	37.19%	25.95%
					$ 2,089,923	$ 2,584,070	$ 2,428,675	$ 2,428,675	$ 494,150	$ 338,752	23.64%	16.21%
Customer Charge (per month rate)				Hold to Current								Hold to Current
Residential (A)	51,372	$ 6.00	$ -	$ 6.00	$ 308,232	$ 256,860	$ 308,232	$ 308,232	$ (51,372)	$ -	-16.67%	0.00%
Commercial (B)	6,384	$ 15.00	$ -	$ 15.00	$ 95,760	$ 81,396	$ 95,760	$ 95,760	$ (14,364)	$ -	-15.00%	0.00%
General Service MLCFR - per kW	24	$ 112.75		$ 112.75	$ 2,706	$ 1,272	$ 2,706	$ 2,706	$ (1,434)	$ -	-52.99%	0.00%
General Service <200 KW - per kWh	648	$ 112.75		$ 112.75	$ 73,062	$ 34,344	$ 73,062	$ 73,062	$ (38,718)	$ -	-52.99%	0.00%
General Service >200 KW	72	$ 112.75	$ -	$ 112.75	$ 8,118	$ 6,840	$ 8,118	$ 8,118	$ (1,278)	$ -	-15.74%	0.00%
					$ 487,878	$ 380,712	$ 487,878	$ 487,878	$ (107,166)	$ -		
Street Lighting (per month rate)				Increase Non-LED by Overall Increase				LED by Overall Increase			Wide swings in PUD proposed	Increase Non-LED by Overall Increase
175 Watt Mercury	144	$ 8.47	$ -	$ 9.84	$ 1,220	$ 1,223	$ 1,417	$ 1,417	$ 4	$ 198	0.35%	16.21%
50 Watt Sodium	528	$ 4.58	$ -	$ 5.32	$ 2,418	$ 1,886	$ 2,810	$ 2,810	$ (532)	$ 392	-22.01%	16.21%
70 Watt Sodium	120	$ 5.20	$ -	$ 6.04	$ 624	$ 522	$ 725	$ 725	$ (102)	$ 101	-16.35%	16.21%
100 Watt Sodium	48	$ 6.37	$ -	$ 7.40	$ 306	$ 280	$ 355	$ 355	$ (25)	$ 50	-8.10%	16.21%
150 Watt Sodium	96	$ 8.13	$ -	$ 9.45	$ 780	$ 775	$ 907	$ 907	$ (6)	$ 127	-0.83%	16.21%
250 Watt Sodium	588	$ 10.96	$ -	$ 12.74	$ 6,444	$ 6,849	$ 7,489	$ 7,489	$ 404	$ 1,045	6.26%	16.21%
400 Watt Sodium	372	$ 15.74	$ -	$ 18.29	$ 5,855	$ 6,586	$ 6,804	$ 6,804	$ 730	$ 949	12.46%	16.21%
				Hold LED Street Lighting to Current				Hold LED to Current				Held to Current Rates in this proposal
25W LED/ 2,188 Lumens	9,840	$ 2.87	$ -	$ 2.87	$ 28,241	$ 22,401	$ 28,241	$ 28,241	$ (5,840)	$ -	-20.68%	0.00%
50W LED/ 3,956 Lumens	2,280	$ 3.71	$ -	$ 3.71	$ 8,459	$ 7,116	$ 8,459	$ 8,459	$ (1,342)	$ -	-15.86%	0.00%
120W LED/ 11,730 Lumens	996	$ 8.13	$ -	$ 8.13	$ 8,097	$ 6,896	$ 8,097	$ 8,097	$ (1,202)	$ -	-14.85%	0.00%
240W LED/ 22,797 Lumens	588	$ 12.73	$ -	$ 12.73	$ 7,485	$ 6,664	$ 7,485	$ 7,485	$ (821)	$ -	-10.97%	0.00%
73W LED Decrotive with pole	468	$ 8.59	$ -	$ 8.59	$ 4,020	$ 3,182	$ 4,020	$ 4,020	$ (838)	$ -	-20.85%	0.00%
					$ 73,950	$ 64,380	$ 76,811	$ 76,811	$ (9,571)	$ 2,861		
Power Factor Adjustment					$ (7,573)	$ (7,573)	$ (7,573)	$ (7,573)	$ (7,573)	$ -	Diff: Divison less Pascoag	
Total Rates and Charges					$ 2,644,178	$ 3,021,591	$ 2,985,790	$ 2,985,790	$ 377,413	$ 341,613	$ (35,801)	
Total Other Revenue (Schedule JS-2, Page 1), add $1,100 to Other Revenue for Net Metering credit issue					$ 107,364	$ 107,364	$ 108,464	$ 108,464	$ 107,364	$ 108,464	$ 1,100	
TOTAL REVENUE					$ 2,751,542	$ 3,128,955	$ 3,094,254	$ 3,094,254	$ 484,777	$ 450,077	$ (34,701)	

		Current	Pascoag	Division/Settlement		Diff Divisions vs PUD	
Total Expenses	JS-1, line 2	$ 3,085,717	$ 3,085,717	$ **3,048,527**		$ (37,190)	
Net Operating Income	JS-1, line 3	$ (333,046)	$ 46,286	$ **45,728**		$ (558)	
Power Factor Adjustment	JS-2, page 1, line 18		$ 7,573	$ 7,573		$ -	
Total Other Income	JS-2, page 1, line 27		$ (107,364)	$ (108,464)		$ (1,100)	
Total Net Revenue Requirement (Sch DGB-COS-1, page 2)		$ 2,752,671	$ 3,032,212	$ 2,993,364		$ (38,848)	Difference, JS-1, column I, line 1
Power Factor Adjustment			$ (7,573)	$ (7,573)		$ -	
Total Other Income			$ 107,364	$ 108,464		$ 1,100	
Net Revenue Required (calculated from above)	JS-1, line 1, col. E and H		$ 3,132,003	$ 3,094,255	3,094,255	$ (37,748)	
Net Revenue Required (Schedule JS-1)			$ 3,128,955	$ 3,094,254	$ 3,094,254	$ (34,701)	
Difference			$ 3,048	$ 1	$ 1	$ (3,047)	

Pascoag Utility District

Rate Design with Gradualism- Impact
Rate Year Ended June 30, 2022

	Usage (kWh)	Usage (kW)		Current Rate	Proposed Rate	Current Revenue	Proposed Revenue	Current Revenue	Proposed Revenue	Dollar Increase	% Increase
Residential (A)											
	300		DIS-kWh	$ 0.03922	$ 0.04558	$ 11.77	$ 13.67	$ 47.95	$ 49.86	$ 2	3.98%
	300		PT	$ 0.10062	$ 0.10062	$ 30.19	$ 30.19				
			CS	$ 6.00	$ 6.00	$ 6.00	$ 6.00				
	500			$ 0.03922	$ 0.04558	$ 19.61	$ 22.79	$ 75.92	$ 79.10	$ 3	4.19%
	500			$ 0.10062	$ 0.10062	$ 50.31	$ 50.31				
				$ 6.00000	$ 6.00000	$ 6.00	$ 6.00				
	1000			$ 0.03922	$ 0.04558	$ 39.22	$ 45.58	$ 145.84	$ 152.20	$ 6	4.36%
	1000			$ 0.10062	$ 0.10062	$ 100.62	$ 100.62				
				$ 6.00000	$ 6.00000	$ 6.00	$ 6.00				
	2,000			$ 0.03922	$ 0.04558	$ 78.44	$ 91.15	$ 285.68	$ 298.39	$ 13	4.45%
	2,000			$ 0.10062	$ 0.10062	$ 201.24	$ 201.24				
				$ 6.00000	$ 6.00000	$ 6.00	$ 6.00				
Commercial (B)											
	500		DIS-kWh	$ 0.04196	$ 0.04876	$ 20.98	$ 24.38	$ 86.29	$ 89.69	$ 3	3.94%
	500		PT	$ 0.10062	$ 0.10062	$ 50.31	$ 50.31				
			CS	$ 15.00	$ 15.00	$ 15.00	$ 15.00				
	800			$ 0.04196	$ 0.04876	$ 33.57	$ 39.01	$ 129.06	$ 134.50	$ 5	4.22%
	800			$ 0.10062	$ 0.10062	$ 80.50	$ 80.50				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
	1000			$ 0.04196	$ 0.04876	$ 41.96	$ 48.76	$ 157.58	$ 164.38	$ 7	4.32%
	1000			$ 0.10062	$ 0.10062	$ 100.62	$ 100.62				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
	3,000			$ 0.04196	$ 0.04876	$ 125.88	$ 146.28	$ 442.74	$ 463.14	$ 20	4.61%
	3,000			$ 0.10062	$ 0.10062	$ 301.86	$ 301.86				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
	5,000			$ 0.04196	$ 0.04876	$ 209.80	$ 243.81	$ 727.90	$ 761.91	$ 34	4.67%
	5,000			$ 0.10062	$ 0.10062	$ 503.10	$ 503.10				
				$ 15.00000	$ 15.00000	$ 15.00	$ 15.00				
General Service <200 KW											
		18	DIS-KW	$ 10.25	$ 5.113	$ 184.50	$ 92.03	$ 911.43	$ 967.17	$ 56	6.11%
	6,104		DIS-kWh	$ -	$ 0.02428	$ -	$ 148.20				
	6,104		PT	$ 0.10062	$ 0.10062	$ 614.18	$ 614.18				
			CS	$ 112.75	$ 112.75	$ 112.75	$ 112.75				
		53		$ 10.25000	$ 5.11271	$ 543.25	$ 270.97	$ 2,259.18	$ 2,373.75	$ 115	5.07%
	15,933			$ -	$ 0.02428	$ -	$ 386.85				
	15,933			$ 0.10062	$ 0.10062	$ 1,603.18	$ 1,603.18				
				$ 112.750	$ 112.750	$ 112.75	$ 112.75				
		105		$ 10.25000	$ 5.11271	$ 1,076.25	$ 536.83	$ 4,729.52	$ 5,044.43	$ 315	6.66%
	35,187			$ -	$ 0.02428	$ -	$ 854.33				
	35,187			$ 0.10062	$ 0.10062	$ 3,540.52	$ 3,540.52				
				$ 112.75000	$ 112.75000	$ 112.75	$ 112.75				
General Service >200 KW											
		350	DIS-KW	$ 10.25000	$ 12.91018	$ 3,587.50	$ 4,518.56	$ 20,302.55	$ 21,233.61	$ 931	4.59%
	165,000		PT	$ 0.10062	$ 0.10062	$ 16,602.30	$ 16,602.30				
			CS	$ 112.75000	$ 112.75000	$ 112.75	$ 112.75				
		620		$ 10.25000	$ 12.91018	$ 6,355.00	$ 8,004.31	$ 28,604.15	$ 30,253.46	$ 1,649	5.77%
	220,000			$ 0.10062	$ 0.10062	$ 22,136.40	$ 22,136.40				
				$ 112.75000	$ 112.75000	$ 112.75	$ 112.75				

	(A)		*	
Percentage increase over TY Revenue (Including Pass-thru Revenue) - Schedule JS-1	$ 341,584	/	$ 8,038,936	4.25%
Percentage increase over RY Revenue at Current Rates - Schedule JS-1	341,584	/	2,752,671	12.41%

	Sch JS-14 Settlement Total Revenue		*		
(A)	$3,094,254	-	$2,752,671	=	$341,583

Notes and Source:
* Schedule DGB-RD-4 from the Company's filing

Pascoag Utility District - Electric
Net Metering Policy

POLICY

This policy sets forth interconnection requirements, equipment specifications, and metering requirements for residential customers who choose self-generation of electric energy using photovoltaic (PV) or wind electric generating equipment. Traditional gasoline, diesel, propane, or natural gas fired portable or permanently mounted emergency generators are explicitly excluded from this policy. Please see our filed tariffs for actual Last Resort Service rates, also known as Power Supply Service rates.

Definitions

"Consumption Meter" means the meter for which all consumer/member usage is metered through and billed at the appropriate retail rate.

"Generation Credit" means the monetary credit allocated to the customer's bill in the form of a bill credit for all metered generation. Generation credits will be based on energy measured on the customer's generation meter. If generation credits for a monthly billing cycle exceed a customer's monthly bill, such net difference will be carried forward as a credit on the next monthly billing cycle. Any remaining excess generation credits as of the December billing cycle for each year will be paid to the customer by check in the first quarter of the next year.

"Generation Meter" means the meter for which all generation is metered through and credited at the Power Supply Service rates.

"Net Metering" means a system of metering electricity in which PUD credits a customer generator for power produced by such generator at the Power Supply Service rate.

General Provisions

1. PUD will offer net metering to customers who generate electricity, provided that the generating capacity of the customer-generating facility does not exceed ten kilowatts. Larger applications must be reviewed on a case-by-case basis.

2. This policy is intended for use at residential properties only: specifically, owner occupied, single family, and not to exceed three-family homes.

3. The customer is solely responsible for securing and complying with all local permitting processes including zoning, electrical, building inspection, and any and all other special permits that may be required.

Net Metering Policy (RIPUC No. 902)

Meters and Metering

1. PV and wind systems used for net metering shall be equipped with two meters; one meter for generation and one meter for customer consumption. The meters shall be connected to the "line side" of the PUD. The additional meter socket (meter must be provided by the PUD only) will be installed by the customer's contractor to measure the amount of electricity produced by the generating facility. Both meter sockets must comply with PUD standards, Rhode Island electric code, and the Burrillville Building Official's requirements and policies.

2. The generating facility must be inverter-based.

3. The aggregate generation capacity on the distribution circuit to which the Customer Generating Facility will interconnect, including the capacity of the Customer-Generating Facility, shall not contribute more than l0% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level that is nearest the proposed point of common coupling as determined by the customer and forwarded to PUD.

4. If a single-phase Customer-Generating Facility is to be connected to a transformer center tap neutral of a 240-volt service, the addition of the Customer-Generating Facility shall not create an imbalance between the two sides of the 240-volt service of more than 20% of nameplate rating of the service transformer.

5. The Customer shall be required to install a manual disconnect for the Customer-Generating Facility located on the line side, within 10 feet of the customer generator meter, and outside of the residence. Disconnect must be clearly labeled, unlocked and readily accessible by utility personnel.

6. Interconnecting Customer will be responsible for reasonable and necessary costs incurred by PUD for the purchase, installation, operation, maintenance, testing, repair and replacement of metering and data acquisition equipment.

7. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under applicable criteria, rules and standards, PUD shall cause such metering equipment to be made accurate or replaced. The cost to repair or replace the meter shall be borne by PUD. Meter readings for the period of inaccuracy shall be adjusted so far as the same can be reasonably ascertained; provided, however, no adjustment prior to the beginning of the preceding month shall be made except by agreement of the Parties. Each Party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other Party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Facility. If either Party believes that there has been a meter failure or stoppage, it shall immediately notify the other.

8. On or before September 1, 2022, the PUD will replace all bi-directional net metering systems with two-meter net metering systems for all existing net metering customers as of the effective date of this tariff. The cost to rewire and replace the bi-directional net meter system with the two-meter net metering system will be borne by the PUD.

Price Credits

1. The amount credited by PUD for electricity produced by the Customer-Generating Facility shall be at PUD's Power Supply Service rate.

2. PUD shall own the meters and the Interconnecting Customer shall pay to PUD a monthly charge to cover meter maintenance, incremental reading and billing costs, the allowable return on the invoice

cost of the meter and the depreciation of the meter, if any. These charges, if any, are set forth in the applicable PUD tariff, as amended from time to time.

Requirements for Inverter Based Installations

1. PUD's distribution circuits generally operate with automatic re-closers, which activate following a trip without regard to whether the Facility is keeping the circuit energized. The Interconnecting Customer is responsible for protecting their equipment from being re-connected out of synch with PUD's system.

2. For Facilities that utilize photovoltaic (PV) technology, it is required that the system be installed in compliance with IEEE Standard 929-2000, "IEEE Recommended Practice for Utility Interface of (PV) Systems". The inverter shall meet the Underwriters Laboratories Inc. Standard UL 1741, Static Inverters and Charge Controllers for Use in PV Power Systems". Based on the information supplied by the Interconnecting Customer, if CMLP determines the inverter is in compliance with UL 1741, the Interconnecting Customer's request for interconnection will be approved.

3. For Facilities that utilize wind technology and employ inverters for production of alternating current, the inverter shall meet the Underwriters Laboratories Inc. Standard UL 1741, "Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems." Based on the information supplied by the Interconnecting Customer, if PUD determines the inverter is in compliance with UL 1741, the Interconnecting Customer's request for interconnection will be approved.

4. The following information must be submitted by the Interconnecting Customer for review and acceptance by PUD prior to PUD's approving the Interconnecting Customer's request for interconnection:

   (a) An electrical one-line diagram or sketch depicting how the inverter will be interconnected relative to the service entrance panel and the electric revenue meters.

   (b) The make, model, and manufacturer's specification sheet for the inverter.

Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond either party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither PUD, nor the Interconnecting Customer will be considered in default as to any obligation under Interconnection Requirements if prevented from fulfilling the obligation due to an event of Force Majeure. However, a party whose performance is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Interconnection Requirements.

Indemnification

The Interconnecting Customer shall at all times indemnify, defend, and hold PUD harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from PUD's performance of its obligations under this Interconnection Requirements on behalf of the Interconnecting Customer, except in cases of gross negligence or intentional wrongdoing by PUD.

Protection Requirements

If, due to the interconnection of the Facility, when combined with pre-existing facilities interconnected to PUD's system, the rating of any of PUD's equipment or the equipment of others connected to PUD's system will be exceeded or its control function will be adversely affected, PUD shall have the right to require the Interconnecting Customer to pay for the purchase, installation, replacement or modification of equipment to eliminate the condition. Where such action is deemed necessary by PUD, PUD will, where possible, permit the Interconnecting Customer to choose among two or more options for meeting PUD's requirements as described in this Protection Policy.

Access and Control

Representatives of PUD shall, at all reasonable times, have access to the Facility to make reasonable inspections. At the Facility, PUD representatives shall identify themselves to the Interconnecting Customer's representative, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Facility. PUD will have control such that it may open or close the aforementioned required meter socket bypass.

Filing Date: November 4, 2021
Effective Date: January 1, 2022

RIPUC No. 109
Canceling RIPUC No. 108

RESIDENTIAL SERVICE RATE

1. DESIGNATION: A

2. APPLICABLE TO:

   This rate is available for domestic uses in an individual residence or an individual apartment.

3. CHARACTER OF SERVICE:

   120-240 volts, 3 wire, single phase

4. RATE SCHEDULE:

Customer Charge per month:	$6.00
Distribution Access Charge per kWh - all kWh :	$0.04558

5. TRANSMISSION COST:

   There shall be included a surcharge representative of the transmission cost to this Department. The terms of this surcharge are provided in the transmission tariff and shall apply to all kilowatt-hours consumed on this rate.

6. LAST RESORT SERVICE, ALSO KNOW AS POWER SUPPLY SERVICE:

   There shall be included a surcharge representative of the Power Supply Service Rate to this Department. The terms of this surcharge are provided in the Power Supply Service tariff and shall apply to all kilowatt-hours consumed on this rate.

7. PAYMENT OF BILL:

All bills are net and payable within 15 days from date of billing. After 30 days, a 1 ½% monthly interest charge will be applied against all outstanding past due balances.

8. TERMS AND CONDITIONS:

The District's Terms and Conditions, where not inconsistent with any specific provision hereto, are a part of this rate.

Filing Date: MARCH 19, 2021

Effective Date: January 1, 2022

RIPUC No. 203
Canceling RIPUC No. 202

GENERAL SERVICE -
MUNICIPAL LOW CAPACITY FACTOR RATE

1. DESIGNATION: M

2. APPLICABLE TO:

   This rate is available to all Town of Burrillville municipal buildings whose utilization factor (or capacity factor) is less than 10% on an annual basis and whose peak load in kW does not normally coincide with Pascoag Utility District's annual or seasonal peak load.

3. CHARACTER FO SERVICE:

   120- 208 volts, 4 wire, three phase, 60 cps.
   277- 480 volts, 4 wire, three phase, 60 cps.
   120- 240 volts, 3 wire, single phase, 60 cps.
   120- 240 volts, 4 wire, three phase, 60 cps.

4. RATE SCHEDULE:

MONTHLY ENERGY CHARGE

Customer Charge per month:	$112.75
Distribution Access Charge per kWh - All kWh:	$ 0.13185

MONTHLY DEMAND CHARGE, per KW

All KW	$5.96

5. POWER FACTOR ADJUSTMENT:

The customer shall maintain a power factor of 90 percent, determined by permanently installed meters or periodic tests. A customer shall install corrective equipment, at customer's expense, to maintain a 90 percent power factor. If a customer's power factor shall fall below 90 percent during any billing period, the customer shall be charged a surcharge as determined by the Department.

6. TRANSMISSION COST:

There shall be included a surcharge representative of the transmission cost to this Department. The terms of this surcharge are provided in the transmission tariff and shall apply to all kilowatt-hours consumed on this rate.

7. LAST RESORT SERVICE, ALSO KNOWN AS POWER SUPPLY SERVICE:

There shall be included a surcharge representative of the Power Supply Service Rate. The terms of this surcharge are provided in the Power Supply Service tariff and shall apply to all kilowatt-hours consumed on this rate.

8. PAYMENT OF BILL:

All bills are due and payable within 15 days from date of billing. After 30 days, a $1^{1/2}$% monthly interest charge will be applied against all outstanding past due balances.

9. TERMS AND CONDITIONS:

The Department's terms and conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Filing Date: March 19, 2021

Effective Date:

January 1,

2022

RIPUC. No. 308
Canceling RIPUC No. 307

COMMERCIAL

1. DESIGNATION: B

2. APPLICABLE TO:

This rate is available to all commercial and industrial customers whose monthly metered demand does not exceed 15 KW.

3. CHARACTER OF SERVICE:

120-240 volts, 3 wire, single phase, 60 cps.
120-208 volts, 4 wire, three phase, 60 cps.
120-240 volts, 4 wire, three phase, 60 cps.

4. RATE SCHEDULE:

Customer Charge, per month:	$15.00
Distribution Access Charge per kWh - all kWh :	$0.04876

5. TRANSMISSION COST:

There shall be included a surcharge representative of the transmission cost to this Department. The terms of this surcharge are provided in the transmission tariff and shall apply to all kilowatt-hours consumed on this rate.

6. LAST RESORT SERVICE, ALSO KNOWN AS POWER SUPPLY:

There shall be included a surcharge representative of the Power Supply Service to this Department. The terms of this surcharge are provided in the Power Supply Service tariff and shall apply to all kilowatt-hours consumed on this rate.

7. PAYMENT OF BILL:

All bills are net and payable within 15 days from date of billing. After 30 days, a 1 ½% monthly interest charge will be applied against all outstanding past due balances.

8. TERMS AND CONDITIONS:

The District's Terms and Conditions, where not inconsistent with any specific provisions hereof, are a part of this rate.

Filing Date: March 19, 2021
Effective Date: January 1, 2022

RIPUC No. 410

Canceling RIPUC No. 409

GENERAL SERVICE <200KW

1. DESIGNATION: C

2. APPLICABLE TO:

   This rate is available to all commercial and industrial customers whose monthly metered demand runs between 15 KW and 200 KW .

3. CHARACTER FO SERVICE:

   120- 208 volts, 4 wire, three phase, 60 cps.
   277- 480 volts, 4 wire, three phase, 60 cps.
   120- 240 volts, 3 wire, single phase, 60 cps.
   120- 240 volts, 4 wire, three phase, 60 cps.

4. RATE SCHEDULE:

MONTHLY ENERGY CHARGE

Customer Charge per month:	$112.75
Distribution Access Charge per kWh - All kWh :	$ 0.02428

MONTHLY DEMAND CHARGE, per KW

All KW	$5.11

5. POWER FACTOR ADJUSTMENT:

The customer shall maintain a power factor of 90 percent, determined by permanently installed meters or periodic tests. A customer shall install corrective equipment, at customer's expense, to maintain a 90 percent power factor. If a customer's power factor shall fall below 90 percent during any billing period, the customer shall be charged a surcharge as determined by the Department.

6. TRANSMISSION COST:

There shall be included a surcharge representative of the transmission cost to this Department. The terms of this surcharge are provided in the transmission tariff and shall apply to all kilowatt-hours consumed on this rate.

7. LAST RESORT SERVICE, ALSO KNOWN AS POWER SUPPLY SERVICE:

There shall be included a surcharge representative of the Power Supply Service. The terms of this surcharge are provided in the Power Supply Service tariff and shall apply to all kilowatt-hours consumed on this rate.

8. PAYMENT OF BILL:

All bills are due and payable within 15 days from date of billing. After 30 days, a 1½% monthly interest charge will be applied against all outstanding past due balances.

9 TERMS AND CONDITIONS:

The Department's terms and conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

10. DEMAND CHARGE:

As previously stated, this rate shall apply to all customers achieving a demand of 15 kw or higher, in any 15 minute period. The customer's highest demand recorded will serve as the minimum billing basis for their demand charge for the ensuing eleven (11) month period, unless and until a higher kw of demand is recorded. That new demand or any ensuing higher demands will be the basis for billing during the eleven (11) months following said reading, notwithstanding the fact that the customer's use may be seasonal or intermittent. Additionally, any such seasonal or intermittent customer is obligated to pay any and all accrued demand charges prior to the customer-requested resumption of service with twelve (12) months of the date of termination of the service.

Filing Date: March 19, 2021

Effective Date: January 1, 2022

GENERAL SERVICE >200KW

1. DESIGNATION: D

2. APPLICABLE TO:

   This rate is available to all commercial and industrial customers whose monthly metered exceeds 200 KW.

3. CHARACTER FO SERVICE:

   120- 208 volts, 4 wire, three phase, 60 cps.

   277- 480 volts, 4 wire, three phase, 60 cps.

   120- 240 volts, 3 wire, single phase, 60 cps.

   120- 240 volts, 4 wire, three phase, 60 cps.

4. RATE SCHEDULE:

MONTHLY ENERGY CHARGE

Customer Charge per month:	$112.75
Distribution Access Charge per kWh - All kWh :	$ 0.00

MONTHLY DEMAND CHARGE, per KW

All KW	$12.91

5. POWER FACTOR ADJUSTMENT:

The customer shall maintain a power factor of 90 percent, determined by permanently installed meters or periodic tests. A customer shall install corrective equipment, at customer's expense, to maintain a 90 percent power factor. If a customer's power factor shall fall below 90 percent during any billing period, the customer shall be charged a surcharge as determined by the Department.

6. TRANSMISSION COST:

There shall be included a surcharge representative of the transmission cost to this Department. The terms of this surcharge are provided in the transmission tariff and shall apply to all kilowatt-hours consumed on this rate.

7. LAST RESORT SERVICE, ALSO KNOWN AS POWER SUPPLY SERVICE:

There shall be included a surcharge representative of the Power Supply Service. The terms of this surcharge are provided in the Power Supply Service tariff and shall apply to all kilowatt-hours consumed on this rate.

8. PAYMENT OF BILL:

All bills are due and payable within 15 days from date of billing. After 30 days, a 1½% monthly interest charge will be applied against all outstanding past due balances.

9 TERMS AND CONDITIONS:

The Department's terms and conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

10. DEMAND CHARGE:

As previously stated, this rate shall apply to all customers achieving a demand of 15 kw or higher, in any 15 minute period. The customer's highest demand recorded will serve as the minimum billing basis for their demand charge for the ensuing eleven (11) month period, unless and until a higher kw of demand is recorded. That new demand or any ensuing higher demands will be the basis for billing during the eleven (11) months following said reading, notwithstanding the fact that the customer's use may be seasonal or intermittent. Additionally, any such seasonal or intermittent customer is obligated to pay any and all accrued demand charges prior to the customer-requested resumption of service with twelve (12) months of the date of termination of the service.

Filing Date: March 19, 2021
Effective Date: January 1, 2022

Settlement-Proposed

RIPUC No. 609
Cancelling RIPUC No. 608

PUBLIC AND PRIVATE LIGHTING RATE

Lamp Size	Monthly Rate	Annual Rate
Mercury:		
175 Watt	$9.84	$118.08
Sodium:		
50 Watt	$5.32	$63.84
70 Watt	$6.04	$72.48
100 Watt	$7.40	$88.80
150 Watt	$9.45	$113.40
250 Watt	$12.74	$152.88
400 Watt	$18.29	$219.48
LED:		
25W LED/2111 Lumens	$2.87	$34.44
50 W LED/ 3816 Lumens	$3.71	$44.52
120 W LED Flood/ 11,730	$8.13	$97.56
240 W LED Flood/ 22,797	$12.73	$152.76
73 W LED Decorative/5,962	$8.59	$103.08

The rates, as specified above, are applicable to all street lights within the Pascoag Utility District's Electric Department service territory for both public and private lights.

The rate for the 175 watt mercury vapor street light is applicable only to such lights currently in service, since such a fixture is no longer offered to PUD customers.

The total cost for public street lighting, in service in PUD's service territory within the Village of Harrisville, will be assessed to the Harrisville Fire District.

The total cost for public street lighting, in service in PUD's service territory within the Village of Pascoag, will be assessed to all classes of electric customers equally. Rhode Island sales tax will be charged where applicable.

The methodology utilized to determine the amount billed monthly to the customers in the Village of Pascoag will be as follows:

Number of Public Street Lights multiplied by the applicable rate per light, as stated herein, divided by the number of customers.

In all cases, both Public and Private lighting assessments will include energy and maintenance.

The Pascoag Utility District will be responsible for the location, size, style and number of fixtures within the Village of Pascoag.

The Harrisville Fire District will be responsible for the location, size, style and number of fixtures within the Village of Harrisville.

Filing Date: March 19, 2021
Effective Date: January 1,2022