DECISION **2023 NSUARB 66**
M010832

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION of the **TOWN OF MAHONE BAY**, on behalf of its **Electric Utility**, for Approval of Amendments to its Schedule of Rates and Charges for the provision of electric supply and services to its customers and its Schedule of Rules and Regulations

BEFORE: Stephen T. McGrath, K.C., Chair
Bruce H. Fisher, MPA, CPA, CMA, Member

APPLICANT: **TOWN OF MAHONE BAY ELECTRIC UTILITY**
James MacDuff, Counsel

BOARD COUNSEL: David Roberts, Counsel
Michael Murphy, Counsel

HEARING DATE: February 14, 2023

FINAL SUBMISSIONS: March 1, 2023

DECISION DATE: **April 28, 2023**

DECISION: **Application is approved, effective the date of this decision, subject to changes and directions to be confirmed in a compliance filing.**

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1.0 INTRODUCTION

[1] The Town of Mahone Bay, on behalf of its electric utility (TOMBEU) applied to the Nova Scotia Utility and Review Board to amend its Schedule of Rates for Electric Supply and Service and its Schedule of Rules and Regulations Governing the Supply of Electric Services. The Board approved the utility's last general rate application in April 2008. Since then, the Board has approved rate changes under TOMBEU's flow-through mechanisms. The last change came into effect on January 1, 2019. There have also been amendments to TOMBEU's Rules and Regulations since April 2008.

[2] As filed, TOMBEU's application proposed an overall average rate increase of 34.8% in the test year. TOMBEU also proposed a 55% increase in its pole attachment fee, which was the only requested change to its Rules and Regulations.

[3] TOMBEU's also expressed concern that it may be liable to make payments for power purchased from NS Power in 2023 that TOMBEU is not required to pay now but may, potentially, become liable to pay in the future. TOMBEU says that it may not be able to recover these payments from its customers in the future because the costs would be for power purchased in the test year. To address this issue, TOMBEU asked for approval to establish a deferral account for these notional future liabilities. If a balance accumulates in this deferral account, TOMBEU would apply to the Board to recover this balance through rates or rate riders upon such terms as may be approved by the Board.

[4] A Notice of Hearing was advertised as required by the *Public Utilities Act*, R.S.N.S., c. 380 (*PUA*). The Board received one letter of comment (Exhibit M-8) and one request to speak at the evening session for the hearing.

[5] The hearing was held in Mahone Bay and livestreamed on February 14, 2023. The following officials from the Town of Mahone Bay appeared before the Board and testified on behalf of the utility: Dylan Heide, Chief Administrative Officer; Ashley Yeadon, CPA, Manager of Finance; and Kim Boutilier, Accounting Clerk. The Town's application was also supported by Aaron Long, General Manager of the Alternative Resource Energy Authority (AREA), who appeared in person at the hearing. TOMBEU's consultants, Paula Zarnett and Trent Winstone, both of BDR NorthAmerica Inc., appeared virtually to support the utility's application. Board counsel consultant, Melissa Whited, Synapse Energy Economics, Inc., also testified virtually at the hearing.

[6] In its application and during the course of this proceeding, TOMBEU claimed confidentiality over certain information filed or presented to the Board. The Board accepts the claim for confidentiality in this proceeding.

[7] The Board approves TOMBEU's application subject to the following:

- TOMBEU must revise its revenue requirement to account for:
    - reduced power purchase costs from NS Power's approved rates;
    - removal of the proposed $15,000 for storm restoration;
    - the recovery of the revised estimate for the costs of this application, amounting to $41,050 in the test year;
    - revenue from pole attachment fees based on the charge approved in this decision;
    - updated working capital based on 12% of the net cash expense after all the adjustments required by this decision; and
    - a return on equity of 7.5%.
- TOMBEU's proposed rates are to incorporate the following cost-of-service, rate design and other changes:

- classify transformer costs as 100% demand-related;
- include meter costs in computing the ratio of classified distribution plant;
- correct the weather-normalization error in its load forecast;
- base customer service charges for the Domestic class on costs classified as customer-related in the cost-of-service study;
- correct the classification error that resulted in $60,644 being incorrectly posted to street lighting, when it should have been posted to distribution systems;
- update the DSM charges in the revenue requirements based on NS Power's rates approved February 2, 2023, and include in existing charges rather than as a separate rider;
- adjust the rates for the Street Light class by 1.25 times the system-wide average change; and,
- other than Domestic Service Time-of-Day and Net-metering, rates are to be adjusted equally if the result would not produce rates that are within a 90% to 110% range. If there are classes outside of this range (aside from Street Lights), they must be capped at the top of the range or increased to the bottom of the range, with any resulting excess or shortfall redistributed to classes within that range to the limits of the range.

- TOMBEU's rate increases in 2023 are capped at 20% for each rate class in the first year, with rates being fully applied effective January 1, 2024, and with any unrecovered revenue from 2023 to be deferred for future recovery, upon application to the Board, beginning January 1, 2025, or as otherwise directed; and

- The Board has not approved TOMBEU's requested deferral account for potential future liabilities but approves the establishment of a deferral account with a more limited scope.

2.0 BACKGROUND

[8] TOMBEU is a distributing utility, supplying electricity service in the Town of Mahone Bay and its vicinity. TOMBEU does not own or operate any electricity generation facilities, although it is currently in the process of building a solar garden.

TOMBEU's distribution system is connected to the Nova Scotia grid. Wholesale electricity supply is purchased under multiple contracts with third parties, which TOMBEU reviews regularly to obtain the best available pricing for the benefit of its customers.

[9] The utility's system peak for 2023 is forecast at 3,691 kW on a weather-normalized basis. The customer base forecast for 2023 consists of 685 Domestic, 76 Small General Service, 69 General Service, 3 net metering and 12 Time-of-Use customers. In recent years, TOMBEU has experienced modest but consistent growth in its customer base and total energy sales.

[10] TOMBEU shares staff and certain equipment with the Riverport Electric Light Commission (RELC) to benefit from economies of scale in providing maintenance on its system. Historically, costs vary from year to year, depending on the volume of certain activities, such as tree trimming, and whether unusual repairs are required in any particular year.

[11] The utility's capital plan for the current fiscal year includes $336,000 in spending, while its capital budget for the test year in this application (the 2023 calendar year) is $145,000. TOMBEU considers the capital budget projects to be urgently required to maintain reliability and safety.

[12] In addition to the challenge of funding its capital budget, TOMBEU faces increasing costs for various supplies and services. Recently, in the context of escalating fuel prices, AREA sought new arrangements for TOMBEU's wholesale supply of electricity. In 2023, TOMBEU intends to purchase supply from NS Power at the rate for municipal customers approved by the Board. TOMBEU estimated that, on an annualized basis per kWh, its cost of purchased power will increase by approximately 40% in 2023

over the 12-month period and the utility is concerned that costs will continue to increase by a further unknown, but significant amount, in the year or years following.

[13] TOMBEU concluded it could not continue to provide service at its currently approved rates without severe detriment to its financial health. As a result, through AREA, TOMBEU commenced the process of preparing a Rate Study to make a general rate application (GRA) to the Board.

[14] As filed, TOMBEU's application proposed a 34.9% rate increase in the test year for all metered customer classes and street lighting. TOMBEU proposed no increase for yard lighting. The proposed overall average rate increase was 34.8%. In the application, the utility stated it would realize an operating loss of $717,331 if it maintained current rates.

[15] The utility is requesting the following approvals in this application:

- The use of the calendar year 2023 as the test year, to enable new rates approved effective January 1, 2023, to meet the revenue requirement for the forecast calendar year.
- A revenue requirement of $2,813,522 for 2023, comprised of the costs shown in Exhibit M-5 (Exhibit 5).
- The accrual of all incurred and budgeted costs for advisors, legal counsel and Board costs related to this application into the test year and the recovery of such costs in the test year.
- A deferral account to reflect any liability associated with power purchases from NS Power commencing January 1, 2023, for which NS Power has or may receive approval from the Board to recover from TOMBEU, for power purchased by TOMBEU in and beyond the test year. If balances accumulate in this deferral account, TOMBEU would later apply to the Board to recover such balances through rates or rate riders upon such terms as may be approved by the Board.
- The Schedule of Rates and Charges as proposed in Tab I of its Rate Study (Exhibit M-1), or as amended to reflect the revenue requirement approved by the Board, to take effect for all electricity consumption or other services rendered on and after January 1, 2023.

- The Schedule of Rules and Regulations Governing the Supply of Electric Services included in Tab J of its Rate Study (Exhibit M-1).

3.0 DISCUSSION AND ANALYSIS

3.1 Calendar Year Test Year (2023)

[16] In calculating the revenue requirement for the test year, the utility used the calendar year of January 1 to December 31. However, the utility's fiscal year runs from April 1 to March 31. The utility was expecting NS Power's rates to take effect on January 1, 2023, and wanted the test year to coincide with the expected timing of NS Power's new rates. The utility stated that a potential consequence of a fiscal year rate increase effective April 1 is not recovering the full year of cost-of-service, or higher rate shock, by concentrating the recovery of the same costs over a shorter period.

[17] TOMBEU indicated that its load and revenues were forecasted monthly, with both the calendar and fiscal year summing the respective 12-month periods. The test year expenses were forecasted using the same amounts as the budgeted fiscal year 2022/23, and included $15,000 for a storm allowance, plus $43,200 for the cost of this rate application. Further, the utility presented a capital plan for the current fiscal year of $366,000; however, its capital budget for the test year in this application is $145,000.

3.1.1 Findings

[18] The presentation of the utility's capital projects in its application was somewhat confusing given the difference between the utility's fiscal year and the use of the calendar year 2023 as the test year. The Board is concerned about the mismatching of the periods when developing the revenue requirement. The Board cautions TOMBEU that selecting a test year that does not match the fiscal year can impede the clear

presentation of its revenue requirement and rate base. Extra effort must be made to ensure that a clear picture of the changes in costs over time is presented.

3.2 Revenue Requirement

[19] TOMBEU is requesting approval of a revenue requirement of $2,813,552 for the test year. This includes the total cost of purchased power, operations and maintenance costs, administrative and general costs, and amortization, plus $100,054. The $100,054 would cover $500 in interest expense and net income of $99,554 based on a return on equity of 8%.

[20] Mr. Heide stated that other than flow-through increases between 2008 and January 2019, the utility has had no general rate increases in 15 years. He noted that the cost of fuel and purchased power has increased significantly because of global events. Further investments in TOMBEU's infrastructure are also required in the near term to ensure the continued supply of safe and reliable electricity service. TOMBEU deemed an increase in rates necessary.

3.2.1 Operating Costs

[21] TOMBEU forecasted its expenses in the test year using the same amounts in its budget for 2022/23 (fiscal year ended March 31, 2023), including a $15,000 storm damage budget and adding $43,200 for its costs in bringing this application. TOMBEU stated in its application that in the test year, it will operate at the same level of cost as for the current year, despite price escalation generally in the economy. The 2022/23 budget includes increases in the cost of living (4.1%), audit fees, shared office costs and regulatory expenses. During the hearing, Mr. Heide noted that the Town has gone through a process of professionalization of the staff.

[22] TOMBEU also noted that there was an increase of 18.5% in salaries from 2020 to 2021 as the utility, along with RELC, hired a full-time apprentice and additional stand-by technician. This increased the utility's full-time team from two to three. During the hearing, Mr. Heide advised that the day-to-day supervision is carried out by RELC's manager under an arrangement with that utility. The Board understands that although these utilities are discussing a more formal structure, to date there has been no agreed-upon reimbursement for that supervision.

[23] TOMBEU has a cost-sharing agreement with RELC, which allows both utilities to benefit from economies of scale in providing services to their ratepayers and maintaining their systems. This agreement has been in place informally since August 2012 and under a written agreement since August 2018, with no expiry date. Staff salaries and stand-by pay are cost shared at 50% by each of the two utilities, and any call-out, overtime or storm restoration is charged 100% to the utility requiring the work.

[24] TOMBEU noted that it shares two resources with RELC: a utility truck purchased by RELC in 2015, and a utility truck owned by RELC. The operating costs of shared resources, such as operations, maintenance and repair, fuel, and insurance, are cost-shared with TOMBEU paying 60% and RELC paying 40%. TOMBEU highlighted that there have been challenges with inventory as it is unclear which utility owns the inventory being used at any given time. TOMBEU noted that the utilities are working towards a few alternatives to mitigate this issue in the future.

[25] The utility currently operates with Town staff, along with the technicians shared with RELC. Mr. Heide noted that the utility is treated independently from the Town and has its own set of books. However, the Town is responsible for liabilities incurred by

its electrical and water utilities utility as they are not distinct legal entities. Mr. Heide noted that there are no employees, other than technicians, that work solely for the utility. Further, when municipal staff's time is charged to the utility, specific hours are allocated to the utility for the specific project or operational requirement.

[26] During the hearing, the allocation of shared resources between the utility and other town departments was discussed. Mr. Heide confirmed there is no written policy outlining how costs are divided. However, a consistent approach is followed where an estimated percentage is applied for employees in the Town's finance and administrative departments who work on TOMBEU matters. Mr. Heide noted that these estimated percentages have generally been accurate, when occasionally compared to actuals. These percentages are periodically reviewed and only updated when a need to change these factors has arisen, based on the judgement of the Manager of Finance. For anything additional, there is an hourly rate charged to the utility. Mr. Heide noted these rates are standardized; i.e., the meter reads performed by the Town staff, on behalf of the utility, are charged based on hourly rates and hours reported on daily timecards.

[27] Mr. Heide also noted during the hearing that they are always assessing the time spent by the Town's finance department to support the utility, especially as it contemplates managing RELC's finances, payables and receivables. However, its anticipated agreement with RELC and its efficiencies have not been accounted for in the test year. Mr. Roberts asked Mr. Heide about the advantages for TOMBEU from this potential agreement with RELC.

> Q. It was pretty obvious in our hearing a couple of weeks ago what's in it for Riverport out of this operation, or this alignment. What's in it for Mahone Bay?
>
> A. (Heide) I think one of the main things that is in it for Mahone Bay is that, you know, we are one of very few now surviving municipal utilities and we have this

> operational partnership where day to day, you know, in terms of equipment, in terms of the PLTs, we absolutely are reliant on our existing partnership. We simply would not be able to sustain the same levels of coverage in terms of responding to outages.
>
> You know, it's been very essential for us to pool our resources on the operational front and, therefore, one of the "What's in it for Mahone Bay?" answers is to ensure that we have that viable partnership, that the fiscal health of the Riverport utility is taken into consideration. We have a going concern there of being able to support the rest of our operation in partnership with Riverport.
>
> Other than that, of course, we've been careful to ensure that we're fully compensated so there's no impact on our taxpayers or ratepayers, and it does improve on our end, in terms of our department, our capacity to deliver those services more effectively for our own utility. As Ashley mentions, we're kind of honing our efficiencies within that process and that experience, I think, is a positive for our ratepayers as well as the ratepayers of the Riverport Electric Light Commission.
>
> [Transcript, February 14, 2023, pp.61-62]

[28] Mr. Heide also noted other efficiencies being explored for the benefit of the utility. These include further opportunities through AREA, asset management programs that Mahone Bay put in place, professionalization of the employees, using Town staff to do meter reading, working towards Nova Scotia certification for a safety program and tendering for vegetation management. Mr. Heide stated that these types of efficiencies would never be possible for a single department to undertake in insolation, hence the electrical utility benefits from being a part of the larger Town structure.

3.2.1.1 Findings

[29] Generally, the forecast operating and administrative costs appear reasonable. To ensure proper accountability of costs for both utilities, the Board encourages TOMBEU to prepare and finalize a formal agreement with RELC for the services provided by the RELC manager to TOMBEU. The Board encourages TOMBEU to continue to identify operational areas of improvement and to develop and implement solutions that will result in the most efficient business processes for the benefit of ratepayers.

3.2.2 Purchased Power Costs

[30] In its application, TOMBEU forecast purchased power costs of $2 million by applying the rates it expected to pay for electricity in the test year to its forecast of weather-normalized electricity sales to serve its customers, and system losses of 4.1%. In the test year, supply will be purchased from NS Power at the Board-approved rate for municipal utility customers and under a separate wind contract through AREA. TOMBEU used the best available information on NS Power's rates to forecast its costs when it filed its application. Purchased power is the largest component of TOMBEU's total cost and is forecasted to increase by approximately 40%, as compared with the current year.

[31] AREA is an inter-municipal agency that procures all power supply for TOMBEU as well as for other Nova Scotia distribution utilities. Considering the serious escalation of fuel prices, AREA sought new arrangements for TOMBEU's wholesale supply of electricity. After evaluating several alternatives, the decision was made to change suppliers and purchase its power supply for 2023 from NS Power at the rate for municipal customers approved by the Board. TOMBEU believes that the new supply arrangement with NS Power represents the best alternative available for its customers in terms of both price and security of supply for the test year.

[32] During the hearing, Mr. Heide noted that TOMBEU has their own source of renewable energy from the Ellershouse wind farm and a solar garden is currently under construction within the community, funded in part by federal and provincial sources. When the solar garden is ready, it will supply additional renewable energy to the utility. Mr. Heide noted that, depending on everything going to plan, the solar garden would become operational around the end of the test year and is estimated to provide between

16% and 18% of TOMBEU's power needs. However, being conservative, it has not been included in the estimates for the test year.

3.2.2.1 Findings

[33] The Board considers the estimated purchased power costs to be reasonable but notes the original application was filed before NS Power rates were approved [2023 NSUARB 12]. The Board directs TOMBEU to submit a compliance filing with updates for its purchased power costs, revenue requirement and proposed rates based on the approved NS Power rates that became effective on February 2, 2023.

3.2.3 Storm Costs

[34] In its original application, TOMBEU included $15,000 in its operating budget for storm restoration. This was based on TOMBEU's estimation that restoration from a major weather event could result in costs in the $60,000 to $90,000 range, with an average occurrence of every four to six years.

[35] In IRs from Synapse, TOMBEU was asked to provide its budgeted and actual storm costs for the past ten years. TOMBEU answered that current management is unaware whether any provision for storm costs was made in previous budgets. TOMBEU also noted that it has no record of historic storm costs. It further stated that it considers itself fortunate that damage from Hurricane Fiona in its service territory was not as significant as in other parts of the province.

[36] TOMBEU assumed that a significant but not catastrophic storm would impose costs of $90,000 and occur every six years, hence the $15,000 allowance. TOMBEU highlighted that if catastrophic storm damage occurred, TOMBEU would still need to file an application for storm recovery with the Board. Further, if the request is

approved, TOMBEU plans to establish a sub-account for these costs or track them offline (in a spreadsheet).

[37] In Synapse's evidence, Exhibit M-9, Ms. Whited stated that the utility's proposal for a storm cost budget allowance was not reasonable at this time because the costs are unsupported by any data. Ms. Whited noted that if the utility is unable to absorb costs associated with storm recovery, it should submit a separate application to the Board. Synapse recommended that the Board reject TOMBEU's proposal for a storm cost allowance at this time.

[38] In the opening statement it filed before the hearing, TOMBEU withdrew its proposal for a storm cost budget allowance. TOMBEU said it would submit a separate application if it were unable to absorb costs associated with storm recovery.

3.2.3.1 Findings

[39] The Board agrees with TOMBEU's withdrawal of the proposed $15,000 storm cost allowance from the revenue requirement in the test year. The Board directs TOMBEU to remove $15,000 from the revenue requirement and update the revenue requirement and proposed rates in a compliance filing.

[40] The Board views the identification and tracking of storm recovery costs as important evidence to support the reasonableness and justification for any future storm budgets or storm recovery applications. The Board directs TOMBEU to establish a sub-account for storm recovery costs and track them through its existing accounting software, if available, as a preferred method. If this is not possible due to software limitations, TOMBEU should track the information in a spreadsheet.

3.2.4 Recovery of Rate Application Costs

[41] In its application, TOMBEU stated that 100% of the estimated costs of this rate application ($43,200) are included in the operating and administrative expenses for the test year. TOMBEU originally stated that it expects to submit a GRA again in the next 18-24 months.

[42] During the hearing, spreading out the application costs was discussed with Ms. Zarnett as a possibility for mitigating rate shock.

> Q. … Now, with respect to study costs, so you want to recover all the study costs in the test year. I'm correct in saying that, I believe?
>
> A. (Zarnett) The costs related to this proceeding.
>
> A. (Zarnett) Yes.
>
> Q. So if we're concerned about rate shock, was there any thought given to actually spreading those study costs over potentially two years, seeing as you potentially will be back in a year or two?
>
> A. (Zarnett) That was initially the plan, however, we now have enough experience to know that the amount that's included is not enough.
>
> Q. Okay.
>
> A. (Zarnett) That budget is insufficient. So in fact, it's going to be a longer recovery.
>
> Q. I'm not sure I understood. So you're saying that the amount in the test year for the actual rate study insufficient?
>
> A. (Zarnett) It is insufficient.
>
> Q. So it will be a longer recovery because you're going to spread the deficiency over an additional year?
>
> A. (Zarnett) As rates that include that amount of money will be in effect for a second year.
>
> Q. Okay. So -- but that's not actually in the test study is it, or in the test year?
>
> A. (Zarnett) No, it isn't. We used the best information that we could as we moved along, we thought we were closer to a new second application and that one year would be enough, however that's not how it's looking now.
>
> Q. So are you requesting that you defer certain portion of study costs? Are you requesting that of the Board, because I don't think we actually have that request on file, or in the application, just to clarify?

> A. (Zarnett) Well, if it would be more of a comfort to first -- perhaps to first revise the estimate and then divide it in half and say it's a two year recovery, we can certainly do that.
>
> [Transcript, February 14, 2023, pp.149 -151]

[43] As part of Undertaking U-11, TOMBEU revised its estimate of the costs of this application to $82,100. TOMBEU noted that if a two-year recovery was selected, the amount to be included in the test year revenue requirement would be $41,050. It submitted that the recovery of these costs beyond the test year could be considered appropriate if the application results in rates in effect for longer than one year. However, if TOMBEU does not bring a new application in two years, the budget provision for recovery of regulatory costs would stay in place as part of the rate for an extended period.

3.2.4.1 Findings

[44] The Board is concerned about the costs of this rate application being included in rates if TOMBEU, despite its good intentions, does not submit a GRA in two years, as expected. This concern is amplified given that this GRA was submitted approximately 15 years after the last application was made in 2008. The Board is concerned about including costs that are no longer applicable in rates. However, the Board also recognizes that there are a number of studies and projects that TOMBEU has proposed to undertake before its next GRA that have not been included in its revenue requirement and could be offset by this allowance if the next GRA is later than anticipated.

[45] The Board approves the proposal to recover the revised costs of $82,100 over two years. The Board directs TOMBEU to revise the original $43,200 amount included in the proposed revenue requirement to 50% of 82,100, or $41,050.

3.2.5 Capital Costs

[46] The proposed capital projects in the test year include:

- pole and line replacements, as required ($25,000);
- new digital meters, as required ($4,000);
- new transformers, as required ($20,000);
- PCB transformer replacement ($83,333); and
- retirement home voltage regulator ($13,220).

[47] The presentation of the utility's capital projects in its application was somewhat confusing given the difference between the Town's fiscal year (April 1 to March 31) and the use of the calendar year 2023 as the test year. To provide context, the utility's 2020-2029 capital plan, by fiscal year, is set out below:

#	Capital Project	Description	TOTAL 10 YR Cost	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
						ELECTRIC UTILITY							
83	Electric Line Replacements	Pole/Line Replacements as Required	225,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
84	New Digital Electric Meters	New Digital Meters as Required	40,000	11,000	11,000	4,000	4,000	2,000	2,000	2,000	2,000	2,000	2,000
85	Run New Lines	From Longhill to Blockhouse RE: Nursing Home	60,000	60,000									
86	Pad Mount Transformers	New Transformers RE: Nursing Home	100,000	100,000									
87	New Street Lights	New Street Lights as Required	40,000	20,000		5,000		5,000		5,000		5,000	5,000
88	Transformers	New Transformers as Required	150,000		35,000	20,000	20,000	15,000	15,000	15,000	15,000	15,000	15,000
89	PBC Transformers Replacement Project	Replace all PBC Transformers (by 2025)	250,000		83,333	83,333	83,333						
90	Voltage Regulator	Retirement Home Voltage Regulator	39,660		13,220	13,220	13,220						
91	BUTU Rate Study #1	BUTU Rate Study #1	32,000		16,000	16,000							
92	Home Heating Program	Extension of existing home heating program	50,000			50,000							
93	Protective Clothing	Protective Clothing	12,556		12,556								
94	Western Circuit Voltage Regulator	An additional voltage regulator is required to offset increased demand on Western circuit.	80,000		80,000								
95	Edgewater Street Lighting	Replacement of light standards on Edgewater St. including additional waterfront electrical connections.	70,000		70,000								
96	Utility Truck	Purchase F-350	80,000			80,000							
97	Wood Chipper	Purchase Utility Chipper (50% Riverport)	40,000			40,000							
			1,269,216	216,000	346,109	336,553	145,553	47,000	42,000	47,000	42,000	47,000	47,000

[Reproduced from Exhibit M-6(i), IR-10]

[48] In its application, TOMBEU noted it is carrying out a modest program to perform needed replacement work on its distribution system. Through IR responses, TOMBEU noted that it postponed the government requirement, that came into force in 2008, to eliminate PCBs from all transformers by December 31, 2025. The postponement of needed distribution work also created a risk of deterioration in the system's reliability, as well as risking TOMBEU not being compliant with governing bodies. TOMBEU stated that short staffing was the reason for the postponement. In 2022, TOMBEU commissioned an engineering review of its distribution system to identify needed capital expenditures over the next several years. TOMBEU noted that all projects identified are required to maintain reliability and safety in its system.

[49] The total amount added to gross capital for the test year is $145,000, of which the majority is related to the continuation of its replacement program for transformers with PCBs. TOMBEU is expecting to invest $25,000 in conductors, $116,554 to replace transformers containing PCBs, and $4,000 to replace analog meters as required. As part of Undertaking U-7, TOMBEU noted the new capital investment will be funded through a combination of the electric capital reserve and Municipal Finance Corporation borrowing.

[50] During the hearing, Mr. Heide explained that the postponement of the replacement of the PCB transformers was due to a combination of limited staff capacity in technicians and at the financial and management level. He noted that, over the last number of years, there has been a focus on increasing staff capacity at the management and financial services level of the Town, which would help in anticipating and planning future capital spending for the utility. Further, he noted some turnover within the number

of power line technicians a couple years ago, which hampered the utility's ability to carry out planned operational requirements. Mr. Heide highlighted that if the capital investment had been carried out earlier, it might have driven the utility to apply for an increase in rates sooner.

[51] Mr. Heide also noted that the utility is now able to look ahead at real infrastructure replacement costs, because of a geospatially located database that keeps track of the assets and the extent of their estimated reinvestment costs. As such, the utility is now more capable, in terms of data, of projecting those future costs and building them into rates. This also allows the utility to make better use of limited resources for infrastructure investment going forward. Mr. Heide stated that the assessment of the distribution system infrastructure concluded that it is generally good. Mr. Heide also positively highlighted that TOMBEU and RELC are pioneering the asset management approach with other municipal electric utilities.

[52] Finally, the utility's ten-year capital plan includes a $50,000 capital expenditure for the Home Heating Program in fiscal year 2023, although this does not appear to be included in the capital projects proposed in the test year. Additionally, TOMBEU's response to Undertaking U-12 advised that the "Intangible Assets" account in its gross plant in service (Exhibit M-5 (Exhibit 1-1)), which increased by $66,000 from actual results for fiscal year 2021/22 to budgeted 2022/23, "encompass expenses expected for such studies as Load Research, BUTU [NS Power's Wholesale Market Backup/Top-Up Service Tariff] and HOME program; as examples."

[53] At the hearing, Mr. Heide told the Board there were no capital expenditures for the home heating program:

Q. You talked a little bit about the home heating program. Can you just describe exactly how that works for me?

A. (Heide) Yeah, absolutely. So the current home heating program, Heat pump Options Made Easy, HOME, I think is the acronym -- is essentially a very straightforward program where we've gone out to the market to get a supplier of heat pumps to manage the program. We've gone out to the market to obtain financing providers.

So essentially, we've paired up those two things so that the individual resident looking to access the service gets their financing and their installation under the same roof. Ultimately, there is no direct cost to the town in that program. As I noted, we have applied to the Federation of Canadian Municipalities for support to undertake a review and possible expansion of that program, but at the current time, that's the extent of the program. And I guess I should say, when I say we, this is a program that is common to Berwick and Antigonish as well. It was developed through AREA.

Q. So there's no capital expenditure by the utility in respect of those?

A. (Heide) No, not in the way the program is currently designed.

Q. And that's not changing in the test year?

A. (Heide) No.

[Transcript, February 14, 2023, pp. 186-187]

[54] The request in Undertaking U-12 was to also include a justification for capitalizing whatever was included in the intangible assets account. TOMBEU noted the intangible assets were studies "expected to provide customers of the Utility long term benefits and therefore qualify as capitalized expenses."

3.2.5.1 Findings

[55] The Board considers the capital plan for the test year to be reasonable, considering the need to meet the PCB regulations. The Board encourages TOMBEU to review its actual and future capital spending regularly to identify investments that can be carried out over an extended period to reduce volatility in rates and to maintain its system reliability and safety.

[56] Regarding the intangible assets included in the utility's rate base, the Board notes that to be properly included as a capital asset, the item must provide a long-

term benefit and be "used and useful in furnishing, rendering or supplying a particular service to or for the public." In this case, the service is the delivery of electrical energy.

[57] Based on the information provided at the hearing, it is likely the HOME Program would be a benefit to some Town residents, but the Board is not satisfied, based on the evidence presented whether such a program, or the anticipated study, would be a benefit to ratepayers overall. At this point, it appears to the Board that the program would more appropriately be borne by the Town's taxpayers instead.

[58] That said, it is not clear from the evidence whether the utility incurred any operating or capital expenditures relating to the HOME Program. The utility is directed to clarify this in its compliance filing, and if the test year includes any operating or capital expenses relating to this program, to remove those from the test year revenue requirement and rate base accordingly. The utility may, if it believes HOME Program expenses are legitimate utility expenses, provide more specific evidence to support their inclusion in its next GRA.

3.2.6 Working Capital

[59] TOMBEU is requesting approval of a working capital allowance of $318,081. This amount is based on an estimated 43 days' payment lag (12%) applied to its forecast $2,650,678 in net cash expenses (cost of purchased power and operations, maintenance, and administrative costs, but excluding amortization). TOMBEU has not included a further allowance for inventory at this time as it is already requesting a large increase in its working capital compared to the 2010 GRA. Further, TOMBEU is attempting, through cooperation with RELC, to reduce its level of inventory.

[60] The requested amount is nearly three times the working capital of $100,000 in TOMBEU's last GRA. TOMBEU noted that it is not aware of the methodology

used in the previous application. It also stated that $100,000 was very conservative at the time and does not provide a reasonable basis of comparison for the working capital requested in this application. TOMBEU did not conduct a lead-lag study for this application. The estimate provided was based on default factors and a practice used by the Ontario Energy Board (OEB).

[61] TOMBEU noted that the OEB used 13% of net cash expenses as the default value for some years and this was later reduced in 2016 to about 7.5% when monthly billing for all customers was mandated. TOMBEU estimated that a slightly lower percentage within this range, around 12%, would be reasonable considering TOMBEU bills every two months for all classes and does not have advanced metering infrastructure (AMI), and therefore has a need for more working capital.

[62] During the hearing, Mr. Roberts asked how many days there are between the time a customer receives service and the time the utility receives payment for that service. Mr. Roberts also asked how many days on average there are between when the utility receives power from its suppliers and the time the utility makes the payment for the service received. Ms. Zarnett stated that no data was analyzed for TOMBEU and that the estimate was based on factors that have been used for other utilities by the OEB.

3.2.6.1 Findings

[63] The Board recognizes that the utility requires a reasonable amount of working capital but is concerned that a working capital allowance that is too high could reduce the utility's motivation to review its operations to find efficiencies. With the utility not conducting its own lead-lag study the Board has some concerns about the

reasonableness of TOMBEU's requested working capital amount but will allow TOMBEU to use 12% of net cash expenses in this proceeding. However, the working capital amount is to be revised based on the changes to the net cash expense arising from this decision.

[64] The Board understands the potential costs involved in a lead-lag study for the utility; however, the Board expects some assessment based on the utility's information to be included in the next GRA. Alternatively, the Board encourages TOMBEU to consider whether a collaborative lead-lag study with other municipal electric utilities in Nova Scotia may be a cost-effective alternative to assess the utility's requirement for working capital based on information that is more closely related to its operations and jurisdiction.

3.2.7 Capital Structure and Rate of Return

[65] TOMBEU asked the Board to approve a return on rate base of 5%. This was based on a deemed capital structure of 60% debt and 40% equity, an estimated cost of debt of 3% and a proposed return on equity of 8%. The request for an explicit return on equity is a departure from the methodology used by the utility in the past. At the hearing, Mr. Heide said while he understands it is possible for the municipal electric utility to return some dividend to the Town, that has never been the practice with TOMBEU. He said the utility needed to maintain a significant operating fund and it has never been in a position to discuss creating a dividend policy (Transcript, February 14, 2023, p. 217).

[66] TOMBEU said the deemed capital structure was consistent with the structure NS Power proposed in its recent GRA and that was found to be reasonable for small distribution utilities elsewhere in Canada. In particular, the OEB uses this deemed

capital structure for the distribution utilities it regulates. It was noted that the utility's actual debt is considerably less than 60% of its capital structure (Exhibit M-6, IR-19 and 20).

[67] TOMBEU's estimated cost of debt is based on inquiries made by a peer utility about the cost for funding its proposed capital projects. The interest rate on TOMBEU's long-term debt reported in its draft March 31, 2022, financial statements ranged from 0.678% to 1.879% (Exhibit M14(i)). While TOMBEU observed that the 3% rate for new debt was very conservative under current market conditions, it was selected to reflect the discussions between the peer utility and its potential lender several months ago (Exhibit M-6, IR-20(b)).

[68] TOMBEU's proposed 8% return on equity was not based on a utility-specific assessment of its investment needs, risk or financial requirements. Instead, the utility's requested rate of return was benchmarked against NS Power's current return on equity of 9%, an observation that NS Power's consultant recommended 10.1% in that utility's recent GRA, and the formula used by the OEB to determine the return on equity for distribution utilities in that jurisdiction, which in 2022 was 8.66% and for 2023 was increased above 9%.

[69] At the hearing, Ms. Zarnett said she considered the 8% return on equity to be conservative, although she was not surprised by the fact that expert evidence in NS Power's GRA covered a range of possible rates of return as low as 7.5%:

> Q. Okay. And Ms. Zarnett, we had an identical discussion to what we had in Riverport, but I just want to put it on the record here again in this proceeding. You'd indicated in your discussion with Mr. Roberts how you went about determining the 8 percent return on equity for this particular application.
>
> You I think, said that at some point in time, and again I'm paraphrasing. So if I misstate this please let me know. But something along the lines of 8.5 percent might even be reasonable based upon what you were seeing. But you were being, I guess, more conservative because of the significant rate increase in this particular application. Is that kind of a fair characterization of your earlier discussion?

A. (Zarnett) Yes.

Q. Yeah. And when I asked you the question at Riverport, I asked you whether you were aware that the evidence, the cost of capital evidence that was filed on Nova Scotia Power's rate application had a range from -- you had referred to the 10.1 or whatever it was high end, and that Nova Scotia Power eventually settled on its 9 percent. There was evidence in that proceeding that it could reasonably be set as low as 7.5 percent. Do you recall that discussion?

A. (Zarnett) Yes, sir.

Q. And I'll go further this time and I'll ask you, why do you think it shouldn't be 7.5, or maybe even 7 in this particular application?

A. (Zarnett) I have not reviewed the evidence of this witness. All I can say about it is that in every case I've ever looked at there has always been evidence of that sort, usually from an academic who will argue strongly that rates of return should be lower.

My business partner who knows more about this stuff then I, has always said that it's indicative that rates of return across the regulated sector are generous because utility stocks in publicly traded companies always trade at a premium. But this is what, when you look around, these are the levels of return regulators are approving in Canada. In the US they tend to be even more, and so we made a recommendation that seemed to be in line with what we were seeing approved by other regulators.

[Transcript February 14, 2023, pp. 217-219]

[70] In its closing submissions, TOMBEU noted that every public utility is entitled to earn a just and reasonable return under the *PUA*. It submitted TOMBEU's proposed capital structure and return on equity should be approved, emphasizing that any profits realized would be reinvested in the utility and would, therefore, flow back to the benefit of TOMBEU's customers.

3.2.7.1 Findings

[71] The fair return requirement and standard was discussed in detail in the Board's decision in NS Power's recent GRA [2023 NSUARB 12 (*NS Power 2023-2024 Rate Application*), paras. 227-237]. Section 45 of the *PUA* entitles a utility to earn a just and reasonable return on its rate base, in addition to the recovery of its operating expenses and other just allowances.

[72] In *NS Power 2023-2024 Rate Application*, the Board reviewed the legal precedents and principles applied to determine a reasonable rate of return and noted that the assessment of these principles in any case before the Board is based on the evidence presented. This typically involves evidence and opinions from cost of capital experts considering matters such as the following:

> - The return must be comparable to the return available in the market on an investment of similar risk: the comparable investment or earning principle.
> - The return must be sufficient to attract new utility capital investment: the capital attraction principle.
> - The return must be sufficient to maintain the financial integrity of the utility: the financial integrity principle.
>
> [*Energy Law and Policy* (Kaizer and Heggie, Ed. 2011)]

[73] In the present case, the evidence supporting the utility's request was minimal. In fact, no evidence was presented to the Board by experts qualified to provide an opinion on TOMBEU's cost of capital. Instead, the requested return on equity was benchmarked against NS Power's return on equity and what the OEB allows distribution utilities to recover in that jurisdiction.

[74] While the Board appreciates that the cost of a cost of capital study comparable to what was before the Board in *NS Power 2023-2024 Rate Application* would be quite significant for a small utility such as TOMBEU, the evidence provided in this proceeding does not provide the Board with the information needed to satisfactorily assess a fair return. The risk profile of a municipal distribution utility with very little debt may be materially different than that of both NS Power and many of the utilities covered by the OEB's generic, formula-based return on equity for distribution utilities.

[75] This is precisely the same situation that was before the Board in its consideration of RELC's recent general rate application [2023 NSUARB 56]. In that case,

the Board recognized the utility's underlying entitlement to a rate of return under s. 45 of the *PUA* but considered the utility did not adequately meet the burden upon it to demonstrate that its requested return was reasonable. For the same reasons expressed in that case, the Board finds that a rate of return on equity of 7.5% is appropriate. While this is below the requested rate, it is the bottom of the range of the rates advanced by experts in NS Power's recent GRA and is the same rate of return the Board approved for RELC.

[76] If TOMBEU feels a higher rate of return is warranted, it is open to it to provide the Board with better evidence in its next GRA. It is possible that this could also be considered in a generic proceeding involving some or all the municipal electric utilities in Nova Scotia. Such a process could be a reasonable and cost-effective way of determining an appropriate rate of return for these very small utilities in their future rate applications. This is similar to the approach that would have been taken by the OEB to set a default return on equity for distribution utilities. It would allow the Board to consider and weigh specific evidence about the risk and circumstances of municipal electric utilities in Nova Scotia and assess the general principles considered when setting a rate of return on equity for those utilities.

3.3 Cost of Service

[77] TOMBEU's cost-of-service assessment was based upon the principles and practices that it applied in its last GRA. As a utility with no generation capabilities, its costs generally relate to purchase and distribution of power functions. Its functionalized costs are then classified as demand, energy or customer-related; and, finally, they are allocated to rate classes.

[78] BDR prepared the Rate Study for this application and noted it is largely consistent with the methodology used in TOMBEU's last rate GRA in 2008, with some changes. In an Information Request (IR) response to Board staff, BDR stated:

> The following table summarizes and compares the methodologies used in the prior (2008) rate study and the methodologies used for this Application. Allocation factors have been updated.
>
> Some changes resulted from changes in availability of information (assets, expenses or miscellaneous revenues) at levels of detail, i.e. as line items. For example, availability of a breakdown of depreciation by asset class for the current study allowed each to be classified as the corresponding asset. The prior methodology (classification of the aggregate amount) would create a different result, to the degree that assets and depreciation are weighted differently. However, the principle involved is the same in each case.
>
> For administrative expenses, classification followed assets in the current study, instead of what appears to be a judgement-based breakdown in the 2008 study. Different approaches can be reasonably defended with regard to administrative expenses. It was the judgment of the consultant carrying out the current study that the proposed treatment corresponds to the method of classifying general plant based on distribution plant.
>
> The methodology for classifying transformers was changed from 100% demand to 70% demand, 30% customer. In the opinion of the consultant, line transformer costs are impacted by the number and density of customers, as well as by total load.
>
> Miscellaneous revenue items were identified separately where possible, and assessed for an appropriate allocation factor.

[Remainder of page intentionally left blank]

Method	2008	2022
Classification of Conductors, Poles and Fixtures	70% Demand, 30% Customer	Same
Classification and Allocation of Street Lighting	Direct Assignment	Same
Classification of Transformers	100% Demand	70% Demand, 30% Customer
Classification of Services	100% Customer	Same
Classification of Meters	100% Customer	Same
Classification of General Plant	By total distribution assets	Same
Classification of Working Capital	By total distribution assets	Same
Allocation of Rate Base – Demand	Non-Coincident Peak	Same
Allocation of Rate Base – Customer	Weighted Customers	Same
Classification of Purchased Power	Demand and Energy as to be billed by supplier	Same
Classification of Lighting	Direct assignment	Same
Classification of Salaries Wages and Other	A factor of 65% demand, 30% customer, 5% lighting, appears to be judgmental	Not a line item. If grouped with distribution, by assets other than meters. If grouped with administration, by rate base.
Classification of Bad Debts	Customer	Bad debts not separated from other administrative costs.
Classification of Other Admin	60% Demand, 30% customer, 10% lighting; appears to be judgmental	By rate base.
Classification of Taxes	Distribution assets	Taxes not separately treated
Classification of Depreciation	In aggregate, by distribution assets	Individually by asset class, same factor as used for the asset.
Allocation of Power Demand	Coincident Peak Responsibility	Same
Allocation of Power Energy	Energy	Same
Allocation of Distribution Demand	Non-coincident peak	Same
Allocation of Distribution Customer	Weighted Customer	Weighted customer, factors reassessed
Allocation of Lighting	Direct Assignment	Same
Allocation of Miscellaneous	Weighted Customers	Revenue items separately allocated
Interest and Net Income	By distribution assets	By total rate base

[Exhibit M-6, IR-36]

[79] In her evidence, Ms. Whited said that, in many cases, the allocation factors used in the Rate Study were based on judgment and TOMBEU was unable to provide any data or analysis to support these allocation factors used in its cost-of-service study. She noted that TOMBEU said it did not have hourly customer load data, research or a metered hourly system load shape so the demand allocators for coincident and non-coincident peaks were based on assumptions. She recommended that TOMBEU file a

proposal within the next 18 months to enhance the data and analysis used to develop cost allocation factors and rates. TOMBEU supports this recommendation.

3.3.1 Cost Adjustments to Net Plant for Street Lighting and Distribution Systems

[80] Synapse noted an increase in net plant for Street Lighting from 2020/21 to 2021/22. TOMBEU said in its response to Synapse's IR-26 that this was due to $60,644 being incorrectly posted to street lighting, when it should have been posted to distribution systems. Since this is a classification error, the net plant balance remains unchanged.

[81] In Synapse's evidence, Ms. Whited recommended the Board require TOMBEU to file a corrected cost of service study before the finalization of new rates with the correct total net plant for each account. In the utility's rebuttal evidence, TOMBEU agreed with the recommendation and suggested that this to be addressed in a compliance filing.

[82] TOMBEU updated Exhibits 6 and 7 in the Rate Study to reallocate the amount of $60,446 from streetlights to distribution assets such as conductors, poles and fixtures, transformers and services in Undertaking U-4. This resulted in an increase in the Street Lighting Service class revenue-to-cost ratio from 41.37% to 52.44%, a decrease in Yard Lighting Service class from 95.70% to 89.72% and a minor decrease in all other classes. TOMBEU considers the utility's proposal to increase rates for all classes equally (except yard lighting) to still be appropriate.

3.3.2 Minimum System v. Basic Customer Methodologies

[83] Synapse challenged TOMBEU's classification of distribution system costs. Synapse described the approach TOMBEU used as based on the minimum system method. In Synapse's words, the minimum system method:

> …calculates the minimum size for each distribution plant type (e.g., poles and fixtures, conductors, transformers), and then classifies these costs as customer-related, while the remaining costs for each plant type are classified as demand related….The costs associated with conductors, poles and fixtures, and transformers are primarily driven by the need to serve demand on the system, and thus it is not appropriate to classify these costs as customer-related.
>
> [Exhibit M-9, p. 8]

[84] Synapse described TOMBEU's classification of 30% of the costs for conductors, poles and fixtures, and transformers as customer-related, as indicative of the minimum system which estimates "the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs to be customer-related." (Exhibit M-9, p. 7)

[85] In contrast, Synapse suggested using the basic customer method. Under this approach, only the meter, service drop and the billing and collection costs are classified as customer-related as these are the "costs that increase or decrease with the number of customers on the system" (Exhibit M-9, p. 10). While TOMBEU classified distribution costs (such as conductors, etc.) as 30% customer-related and 70% demand-related, Synapse would classify them as 100% demand-related. The result is that:

> …the costs allocated to the Domestic, Time of Day, and Net Metering classes increase by approximately 2-3 percent under the basic customer method, while costs allocated to other classes decrease.
>
> [Exhibit M-9, p. 11]

[86] In response, TOMBEU's consultants asserted that:

> … The minimum system method has a long history of use in Nova Scotia for both NSPI as the major utility in the province, and also for the municipal utilities. This approach is also

> widely used in other Canadian jurisdictions, for small distribution-only utilities as well as for larger and integrated utilities. TOMBEU was not previously directed by the Board to review alternative methodologies and submit findings, and has not done so. It would be inappropriate for it to be changed for TOMBEU in this proceeding.
>
> [Exhibit M-10, p. 4]

3.3.3 Transformer Allocation

[87] In Exhibit M-1 (Exhibit 4-2 and Exhibit 4-3), TOMBEU classified transformer costs as 30% customer-related and 70% as demand-related, even though in TOMBEU's previous study, transformers were treated as 100% demand-related. TOMBEU explained that "line transformer costs are impacted by the number and density of customers, as well as by total load." (Exhibit M-6, p.38)

[88] In its final argument, TOMBEU agreed that, if the Board wants consistency between NS Power and the smaller municipal electric utilities, transformers can be classified 100% to demand.

3.3.4 Findings

[89] The Board is concerned with the limited data and analysis that is specific to TOMBEU, and the overly subjective nature of the allocation factors used in its cost-of-service study. TOMBEU has committed to addressing this concern and said it will file a proposal within the next 18 months to enhance the data and analysis used to develop cost allocation factors and rates.

[90] The Board does not believe that a fundamental change to the utility's historical method of allocating its distribution system costs is appropriate at this time. In addition, there is value in ensuring some underlying consistency in the costing methodologies used amongst local electrical utilities, especially the smaller municipal utilities. As such, the Board accepts the methodology used in the Rate Study prepared

for TOMBEU in this proceeding, except that transformers should be 100% demand-related, as was the case in TOMBEU's past applications. The Board anticipates that this issue may be one that is more thoroughly considered in this jurisdiction when NS Power completes its next cost-of-service study, which is expected no later than December 31, 2025.

[91] The Board directs TOMBEU, in its compliance filing, to correct for the misallocation of costs to streetlights.

3.4 Correction of Errors

[92] In its rebuttal evidence (Exhibit M-10, p.8), TOMBEU acknowledged two minor errors requiring corrections including "in the load forecast related to the weather normalization which will impact the forecast per customer energy usage (kWh) for each metered rate class" and the omission of the meter balance from the total for the "ratio of classified distribution plant for purposes of classifying general plant and working capital". TOMBEU has agreed to correct both in its compliance filing.

3.4.1 Findings

[93] The Board directs TOMBEU to correct these errors in its compliance filing.

3.5 Rates and Charges

3.5.1 Customer Service Charges

[94] In its application, TOMBEU proposed that all customer service charges should be increased proportionately with the overall increases in rates.

[95] Ms. Whited recommended that the Domestic Service class charge be maintained at its current level given her calculations for customer-related costs under the

basic customer method. BDR did not agree. It argued that the proposed approach is consistent with NS Power's GRA proposal and the charges of other small utilities. The proportional increase in charges was generally consistent with TOMBEU's approach to other rate components. Ms. Zarnett explained that every customer in the class would bear the increase *pro rata* with its prior bill. It wouldn't have a different impact on a smaller consumer than a larger consuming customer.

[96] The current service charge for Domestic Service is $11.91/month. By Ms. Whited's calculation, even using the minimum system method proposed by TOMBEU and accepted by the Board earlier in this decision, the estimate for the Domestic class service charge should be approximately $13, rather than $15.69 TOMBEU proposed.

[97] During the hearing, when discussing whether the customer service charges should be increased proportionately in line with the overall increases, TOMBEU agreed that the customer charges can be set based on the cost-of-service calculations. Ms. Zarnett also confirmed that calculating the customer charge based on the cost-of-service study and assuming an allocation of transformers at 100% demand would yield a customer charge of $11.67. In Undertaking U-13 provided by Synapse, Ms. Whited confirmed the suggested methodology by BDR for calculating the customer charge: amortization of customer-related distribution assets; amortization of metering and billing related assets; operations and maintenance expense on customer-related distribution assets and metering and billing expenses.

3.5.1.1 Findings

[98] The Board finds it reasonable for the customer charges to be updated to reflect the cost of service. While there are questions about the current cost-of-service

study, TOMBEU's recalculated customer charge more closely reflects the evidence of customer-related costs before the Board than the proportional increases. The Board approves the customer charge changes, based on the customer-related costs in the cost-of-service study, using the allocation methodology employed by BDR in the Rate Study for distribution costs, with the exception that transformer costs should be allocated 100% to demand. This will apply to the service charge for the Domestic Service class. The Board directs the utility to confirm the calculations for the final charge in the compliance filing, applying all the revisions directed by the Board in this decision.

3.5.2 Demand Side Management Costs

[99] In its application, TOMBEU proposed to add a separate charge of 0.819 cents per kWh to its bills for all metered customer classes for demand side management (DSM). This was intended to reflect the DSM rate NS Power proposed to charge to municipal utility customers in that company's recent GRA. In that case, NS Power had also proposed to include DSM as a separate charge on bills; however, that request was withdrawn in its rebuttal evidence in the face of concerns advanced by some parties in that proceeding.

[100] The Board approved NS Power's DSM rider in *NS Power 2023-2024 Rate Application*, but the DSM charge is incorporated in its energy charges. The approved NS Power DSM charge for municipal electric utilities is also less than anticipated by TOMBEU when it filed its application.

[101] In its Final Argument in this proceeding, TOMBEU similarly withdrew its request to include a separate line item for DSM on its bills. It also noted it would adjust its revenue requirement to update its assumptions about the DSM charge.

3.5.2.1 Findings

[102] TOMBEU is directed to update, in a compliance filing, its revenue requirement and proposed energy charges to account for the reduced purchased power costs to reflect the Board's decision in *NS Power 2023-2024 Rate Application* and the other changes directed by the Board in this decision.

3.5.3 Declining Block Rate Structure

[103] TOMBEU has long employed a declining block rate structure for Domestic Service, Small General Service, General Service and Large General Service. In response to Synapse IR-6, TOMBEU addressed the cost basis for declining block rates, as follows:

> In a declining block rate structure fixed and variable non-fuel costs are intended to be recovered both through the service charge and through differential between the 1st block energy charges and the balance block charges. It is intended that all such costs are recovered when each customer "fills" the 1st block, and then the second block recovers demand and energy related only.
>
> TOMBEU has not carried out a study to review the relationship between the allocated fixed "customer related" costs of its classes and the costs recovered through the service charge and block price differentials.
>
> [Exhibit M-7 p. 4]

[104] Ms. Zarnett noted that declining block rates were more widely used in the past by water and electric utilities. The block rates offered some protection to smaller customers against the fixed component of a bill. They allowed the utility to bill for a smaller fixed component and then collect the shortfall from the differential between low and higher use (billed at the higher rate). Ms. Whited's report indicated that many jurisdictions moved away from declining block rates, particularly for residential customers, because they are difficult to justify from a cost-of-service perspective. Ms. Whited recommended the Board direct the utility to file a proposal to eliminate the declining block

rate structure, unless the rate structure can be supported by evidence that demonstrates it is cost-effective.

[105] In Undertaking U-3, the utility notes that 87.7% of its revenue is derived from consumption or energy charges with 12.3% from fixed charges. This includes unmetered street lighting and yard lighting customer classes where 100% of revenues are derived from a fixed charge. The proportion of variable versus fixed charges for metered customer classes only is 90.0% variable and 10.0% fixed. The utility computed these proportions based on Test Year forecast number of customers and consumption, and the rates proposed by TOMBEU.

3.5.3.1 Findings

[106] The Board understands TOMBEU's concerns about the impact of high-rate increases on customers. However, the utility operates on a cost-of-service model, as set out in the *PUA*. This prescribes the way the Board must assess the application. TOMBEU's rates and charges should be the same for substantially similar circumstances and conditions of service. If the rates do not accurately reflect the cost associated with serving additional load, lower-usage customers may end up subsidizing higher-usage customers. Lower prices for higher levels of electricity consumption also reduces an incentive for energy efficiency and conservation.

[107] The parties agreed that the current declining block rate structure does not appear to be based on cost-of-service principles. TOMBEU has not provided any cost-of-service analysis that supports retaining the declining block whereas it provided its estimated revenue composition from both consumption and fixed charges. Nevertheless,

the Board sees value in a more detailed review of the impact of removing the second block and any alternate proposals, prior to recommending its elimination.

[108] The Board directs the utility to review whether maintaining the second block rate can be justified from a cost perspective and return to the Board with the results of its analysis in its next GRA.

3.5.4 Revenue-to-Cost Ratios

[109] Exhibit M-5 (Exhibits 5 and 6) set out calculations showing a revenue shortfall in 2023 of $717,331, and that an overall average rate increase of 34.8% is necessary to satisfy TOMBEU's proposed revenue requirement. In rebuttal evidence filed by BDR, it was noted that the Board's decision in *NS Power 2023-2024 Rate Application* resulted in rates that were lower than the power purchase costs forecast in TOMBEU's application and, if updated, would reduce the proposed rate base, revenue shortfall, and average rate increase to electricity customers needed to recover the revenue requirement.

[110] With the substantial deficiency under existing rates, TOMBEU's cost of service analysis shows that all rate classes are under-recovering revenue, except for Yard Lighting Service, which was within the 95% to 105% range the Board generally considers to be reasonable. Metered rate classes are shown as recovering between 70.1% and 78.5% of their allocated cost of service. Street Lighting Service, at only a 30.8% revenue-to-cost ratio, is substantially under-recovering its allocated costs under existing rates.

[111] To address the shortfall in revenue under current rates, TOMBEU proposed to apply a uniform rate increase to all rate classes while maintaining Yard Lighting at existing rates. The proposal brought all rate classes within the 95% to 100%

range except for Street Lighting Service, which would still only be recovering less than half of its allocated costs (41.4%).

[112] As discussed earlier in this decision, in its response to Synapse IR-16 (Exhibit M-7), TOMBEU recognized that a large increase in plant in service shown in Exhibit M-5 was the result of an error. An addition to street lighting plant of approximately $60,000 between fiscal years 2020/21 and 2021/22 should have been posted to distribution systems. This overstated the costs allocated to Street Lighting Service in the Rate Study, and as a result, somewhat understates the revenue-to-cost ratio for Street Lighting Service (and marginally overstates it for other rate classes).

[113] While noting that TOMBEU should file a corrected cost of service study to account for this, Ms. Whited's own calculations showed that after correcting for this error, TOMBEU's proposed uniform rate increases for all classes except Yard Lighting Service still resulted in a substantial under recovery of costs for Street Lighting Service. Additionally, the revenue-to-cost ratios for Yard Lighting Service and Domestic Time-of-Day Service were slightly below the 95% to 105% range.

[114] Based on her recommendation that the Board require TOMBEU to use the basic customer methodology for allocating distribution system costs (which the Board has not accepted in this proceeding for the reasons considered earlier in this decision), correcting for this error and applying uniform rate increases puts all metered rate classes within the 95% to 105% range (except Domestic Time-of-Day Service (91%)) but resulted in a substantial over recovery for Yard Lighting Service and under recovery for Street Lighting Service.

[115] Ms. Whited considered the proposed rate increases were not consistent with the results of TOMBEU's cost-of-service study because it did not adequately address the under-contribution from Street Lighting. To address this, Ms. Whited proposed that the Street Lighting Service rates be increased by 125% of the system average rate increase and that the over contribution for Yard Lighting (based on her basic customer methodology for allocating distribution system costs) be reduced by half. While having some concerns about the Domestic Time-of-Day Service, Ms. Whited recommended the same increases for this class as for the Domestic Service class.

[116] In its rebuttal evidence, BDR highlighted that Ms. Whited's evidence was that the revenue-to-cost ratios supported equal percentage rate increases for all rate classes except Yard Lights Service and Street Lighting Service. BDR also noted that design of the Domestic Time-of-Day Service rates established a fixed relationship between those rates and the Domestic Service Rates.

[117] BDR noted it did not agree with the basic customer approach and, therefore, said there should be no change to the rates for Yard Lighting Service, "or a very small adjustment if required to keep this class within the Board-approved range once final corrections are made to the study." (Exhibit M-10, p. 7)

[118] BDR said it appeared that under either approach to allocating distribution system costs, Street Lighting was significantly below the range. While noting that the speed of adjustments to revenue-to-cost ratios is "a matter of judgment, having regard to both the objective of fairness and the principle of gradualism and avoidance of rate shock," BDR said if the Board felt something other than the proposed equal increase was appropriate, the adjustment proposed by Ms. Whited would narrow the revenue-to-

cost gap. BDR said future adjustments could be considered "following completion of the recommended work to improve cost allocation factors and to review the direct costs associated with providing these services." (Exhibit M-10, p. 8)

[119] In its Final Argument, TOMBEU submitted:

> …Given the overall circumstances of this case, particularly the magnitude of the increase on the domestic and general classes and the fact that TOMBEU will be conducting further studies with better load research data and returning to the Board for another General Rate Application in the near term, TOMBEU recommends the Board order only a limited adjustment to the Street Lighting class on account of R/C ratios in this case as it deems appropriate, with all the metered classes sharing in that equally. TOMBEU anticipates that it will be required to more fully address the issue of all the R/C ratios in its next General Rate Application when the data underpinning the study is more reliable.
>
> [TOMBEU Final Argument, p. 10]

3.5.4.1 Findings

[120] The Board agrees that a larger adjustment for Street Light Service is appropriate and directs TOMBEU to adjust the rates for this class by 1.25 times the system-wide average change. Subject to the comments below about Domestic Service Time-of-Day and Net-metering rates, the rates for the remaining rate classes (aside from Street Lights) are to be adjusted equally until the adjustment produces a revenue-to-cost ratio for each class that either reduces its revenue-to-cost ratio to no less than 90% or increases its revenue-to-cost ratio to no greater than 110%. If the revenue-to-cost ratio for one or more rate classes reaches these limits, further equal adjustments will apply to any rate class that has not reached its limit.

[121] With these adjustments, there will be one or more rate classes outside of the Board's typical 95% to 105% range. However, the Board recognizes that there are data limitations with the Rate Study that TOMBEU has said it would address before its next GRA. The Board expects the utility will further consider any revenue-to-cost ratio outliers at that time.

[122] TOMBEU's Domestic Service Time-of-Day rate is an optional rate that is available to customers with electric thermal storage equipment and electric in-floor radiant (i.e., hydronic) systems. The rate is designed with varying energy charges, depending on the time of the year, day of the week and time of the day. The energy charges for this service are based on the Domestic Service second block energy rate. On-peak charges are twice that rate, off-peak charges are 58.10% of that rate, and charges in the shoulder periods are equal to the Domestic Service second block energy rate.

[123] In her evidence, Ms. Whited raised a concern about the assumptions around the demand allocation factors for the Domestic Time-of-Day Service. In Undertaking U-2, TOMBEU said it would take certain steps to review this issue. The Board finds that the energy charges for the Domestic Service Time-of-Day rate under this decision will maintain its current relationship with the Domestic Service rate. However, the utility is directed to review this rate and address the issue in more detail in its next GRA.

[124] Although the Rate Study presented TOMBEU's net-metering program as if it were a distinct rate class, the utility said this was done to simplify calculations. As the utility noted in its response to Synapse IR-8(a) (Exhibit M-7):

> Net metering is not actually a "rate", but an arrangement in which a customer with generation as well as load can supply part of its own need and receive compensation for the generated supply in the form of a credit applied to the cost of the electricity consumed. Net metering is available to customers in all metered classes. The rate otherwise applicable would be whichever of the Utility's metered rates (Domestic, Small General Service or General Service) would apply to that customer's load if the customer did not have a generator.

[125] As such, there are no specific rates for net metering. At present, all TOMBEU's net-metering customers are Domestic Service customers, so the service

charge and energy rate for the Domestic Service class approved in this decision would apply to them. The only difference is, if the electricity supplied to the utility by the customer generator exceeds the amount supplied by the utility to the customer in a billing period, the customer will be billed the greater of the applicable non-kWh monthly charges or $15.00 for that billing period. TOMBEU did not propose any amendment to this provision in this proceeding.

3.5.5 Phasing-in the Rate Increase

[126] As noted earlier in this decision, TOMBEU's application proposed a 34.8% overall average rate increase. As proposed in the utility's application, the rates for its metered customer classes would increase by 34.9%. The impact of the proposed rates in the original application on the average bi-monthly bill for a Domestic Service customer is approximately $120 ($720 per year) (Exhibit M-6(i), IR-6 (adjusted to remove the effect of a rebate that is not part of the approved rate design)). Customers who use more energy than average (e.g., electric heat customers) would see higher increases while those customers using less energy than the average would see smaller increases.

[127] TOMBEU noted in its application it was very conscious of the hardship that an increase of this magnitude may impose on its customers and anticipated the Board would share this concern. It noted that it was exploring mechanisms for rate mitigation and funding to support that.

[128] In its opening statement, the utility said the Town was working to improve programs to support its customers in reducing heating costs, but it did not consider a deferral of any part of the proposed rate increase to be appropriate:

> With respect to the rates requested in the Application, the Town of Mahone Bay appreciates that the magnitude of the increase is significant for its customers. As noted in the Application and in its responses to Information Requests, the Town has continued to

consider ways to mitigate the impact on its customers. We are working to improve programs which support our customers in reducing their heating costs.

The Board's decision in NS Power's General Rate Application will reduce the costs of power purchased from NS Power as compared to what was assumed in the Application, and the Town expects that it will be in a position to adjust the requested rates to take this into account as part of the Compliance Filing in this proceeding. This will have a downward impact on the requested increases as compared to the Application as filed.

Our small utility lacks the financial capacity to defer the remaining increases, nor is the Town in a position to backstop Utility operating debt. Even should financing be secured by the Utility, this would attract significant additional financing costs that would eventually need to be borne by our customers. The Town of Mahone Bay is opposed to further rate mitigation due to the Utility's lack of financial capacity to support a deferral, and in any case we do not believe such a deferral would be in the best interest of our customers.

It is our intention to operate within our financial capacity and to avoid incurring additional costs and burdening future customers by pushing cost increases down the road. By addressing rising costs with appropriate rate increases today, considerate of the impacts on our customers, we will be better able to protect customers from significant rate increases in the future, continuing to increase the supply of own-source renewables.

[Exhibit M-11, p. 2]

[129] This was explored further in questions from the panel at the hearing, where Mr. Heide discussed some of the Town's programs to assist customers facing large bills:

Q. ...

You said the Town was focusing on those on fixed income and hardships in the Town structure dealing with individuals' electric heat. Could you expand on that a little bit just as context for us in terms of what you are doing?

A. (Heide) Yes, absolutely.

So you know, in the broader context, obviously the Town has set some significant goals in terms of emissions reduction as a community. And as a tool to pursue that, we have launched a program to support the installation of heat pumps in homes. That program's been operational for more than a year. It is currently being reviewed.

We've put forth an application to the Federation of Canadian Municipalities for a review of that program but, you know, ultimately, that is a program intended to streamline and support the process for residents to reduce their heating costs and/or convert away from fossil fuel usage for home heating.

Council is exploring opportunities to further incentivize participation in that program. There's been a -- certainly a significant level of discussion at Council since we made this Application. It was actually in the same night that the Council resolved to apply for this rate increase, staff were directed to explore opportunities to implement improvements to that program.

Similarly, we -- you know, we've looked at the situation of individual customers facing large bills during the winter months and we're certainly exploring opportunities to be sympathetic to, you know, billing cycles and people's challenges in that final quarter of the year.

So we do have those kind of programs which are either operational programs or providing a direct support to a homeowner, so those are the kind of programs that are in place now.

Obviously, separate from the electric utility, the Town has low income rebate program which is permissible under the *Municipal Government Act* which provides a significant amount of relief direct to property owners, but that is targeted to property tax relief, albeit it's a means tested support for individuals dealing with higher bills, so it would also apply to those same individuals.

[Transcript, February 14, 2023, pp. 115-117]

[130] Mr. Heide was also asked about the utility's ability to manage a phase-in of the rate increase, if that were to be ordered by the Board:

Q. Mr. Heide, the discussion about phasing in the potential impact of the rate increase, I just want to make sure I'm clear on the utility's position. You seem to be talking about two things. One is the financing difficulties and then the other is you just don't think, I think, I should be done anyway.

So on the financing side of things, are you saying that it's not possible if the Board were to say, we want you to phase this in over two years, for the utility to carry that, that it's not going to be financially possible?

A. (Heide) We're saying we don't have the ability to carry it, obviously on our books, or depending on the town, to backstop the utility's debt. You know, ultimately if directed to do so we would have to source market financing through the utility. It's my understanding we do have the ability to go to the market for that. There would be no preferential treatment of that debt. So that would be our option if directed to pursue it.

Q. And I thought in some of the pre-filed materials there was an indication that the utility was actually looking at those potential options. Was that actually explored, or how far down that path did you go?

A. (Heide) So as, you know, essentially a part of the effort to be more efficient and combine these type of work with our other MEUs, I think the Board is aware that we have all contracted BDR, we've all been essentially exploring these alternatives together. So some exploration has been done collectively of this option.

As noted, some of our other municipal utility partners have been willing to go further in terms of commitment in that regard, but ultimately we benefit from that same exploration process which has gone on behind the scenes. So yeah, I think that's why we noted that that exploration has been taking place, but ultimately, that's due diligence and it's a part of our shared process with the other MEUs to defray costs for this type of preparation.

Q. So again, I just want to be clear, if the Board were to order it, whether the utility just can actually manage it, you know? If the Board were to order it, are we in a scenario where it's just impossible for the utility to comply with phasing it in over two years?

A. (Heide) No, I don't believe that that is impossible.

Q. Okay. So it's more then I think, a preference that you would prefer that the full 30 percent or whatever it happens to be, be passed along in one year, rather than phase it in over two or three years with the additional carrying costs associated with that?

A. (Heide) I think it's certainly fair to say it's the council's policy or approach to handling this type of rate increase, preference is a way it could be characterized. It's ultimately, you know, council's decision that it is in the best interest of our ratepayers to do put it all into the first test year as opposed to spreading it out.

Q. And have you heard from your customers about what they feel is in their interest to do with respect to the 30 percent increase?

A. (Heide) Obviously, we're a very small town, so our council members have a lot of direct interaction with residents and that's mostly on an informal basis. I know there's one formal registrar with respect to tonight's public session. But you know, so absolutely we have heard, and we understand that it is a concern for many.

Ultimately, I think there's perhaps not a great understanding from people about the notion of deferring, or smoothing, or mitigation, as ultimately just another form of passing along additional costs to the ratepayer. And in particular, the notion that rates today will be the responsibility of a future ratepayer, something that we have grappled today in terms of our preparation to be on receiving end of that treatment from Nova Scotia Power. Ultimately, don't think that it's appropriate to pass along that type structure, if it's possible to be transparent and put the cost where it actually belongs.

[Transcript, February 14, 2023, pp. 166-171]

[131] TOMBEU revisited the issue again in its final argument:

During the hearing, TOMBEU was questioned about potential options to mitigate the magnitude of the rate increase. In response to questions from Board Counsel, Mr. Heide confirmed: "Ultimately, we [TOMBEU] don't feel that taking on additional financial costs associated with borrowing to defer would be in the interest of our ratepayers." Mr. Heide noted the Town is taking steps to focus on individuals on fixed incomes or who are experiencing specific hardship. Mr. Heide also confirmed that there are no additional cash or accounts receivable balances available for rate mitigation given the fairly substantial deficit that TOMBEU is expected to incur as a result of new rates not taking effect on January 1, 2023 as originally hoped for.

[TOMBEU Final Argument, p. 3]

[132] The utility went on to note it was concerned that deferring costs would only compound the increase that would be sought in the future, citing evidence that actual fuel costs for NS Power's Municipal Tariff in 2023 may be understated. It also noted its

application was based on an assumed start date for new rates on January 1, 2023, whereas new rates will come into effect several months later.

3.5.5.1 Findings

[133] As the Board discussed in *NS Power 2023-2024 Rate Application*, there are trade-offs involved with using deferrals to phase in rate increases, as they often result in higher costs in the longer term. This must be balanced against the rate-setting principle that rates should be stable, and experience minimal unexpected changes that are seriously adverse to existing customers.

[134] While the Board accepts that the Town of Mahone Bay is making efforts to assist residents through programs such as those supporting the installation of heat pumps and low-income rebate programs, the Board has no jurisdiction over those Town programs and cannot review how they are designed, targeted or applied. The Board cannot direct that they be provided or continued. The Board's ability to mitigate rate shock, in the circumstances of this case, is limited to its ratemaking function and its authority under the *PUA*.

[135] Even factoring in such programs, it is not clear they would adequately mitigate the rate increases for a broad range of customers. The specifics of those programs were not before the Board, aside from the passing references made to them by Mr. Heide. The heat pump program may assist some customers with electric heat to reduce their heating costs, but the program is not focused just on those existing customers and appears in part to be designed to encourage people to convert from fossil fuel-based space heating. The low-income rebate program that was mentioned provides tax relief to some property owners. As such, it is not clear that renters would benefit or

that it would apply to moderate income customers who have high energy burdens. Also, as highlighted in the presentation to the Board during the evening session, there are some utility customers who live outside of the Town and may not benefit at all from any municipal programs offered by the Town to its residents.

[136] While these programs will undoubtedly help some people, given the magnitude of the increase, and to mitigate rate shock to a broader range of customers, the Board finds it is appropriate to phase in the proposed rate increases. As the Board found in RELC's recent GRA, in the present circumstances, the trade-offs involved in deferring the proposed rate increase for a period any longer than two years would not be in the best interests of the utility and its customers.

[137] Additionally, the Board finds that it would be appropriate to reflect more of the increase in the first year to reduce interest costs associated with the deferral, given the likelihood that under-recovered fuel costs will be added to TOMBEU's purchased power cost through NS Power's fuel adjustment mechanism. As such, the Board directs a two-year phase-in of the rate increase, with the rate increase in 2023 capped at 20% for each rate class and increasing to the full approved increase beginning January 1, 2024.

[138] While this will only modestly mitigate the increase for some rate classes and only for a short time, the Board recognizes TOMBEU's concern about pushing unrecovered costs into a future period when they may only compound future rate increases that could also be significant. Unfortunately, the evidence presented by the utility in this case did not provide comfort that its rates would remain stable and not

increase for a period that would allow a more extended phasing-in of this significant rate increase. As a result, even the temporary deferral leaves a very large increase.

[139] The difference between the rate cap in the first year, and the full rate approved in this decision, is to be deferred for later recovery by TOMBEU, with interest. The Board directs the utility to track the deferred revenue in 2023 by rate class and to apply to the Board in 2024 for approval to begin recovering the deferral beginning January 1, 2025. If TOMBEU files a GRA before that time, the recovery of this deferral may be included as an issue to be determined in that proceeding.

[140] Finally, the Board must also be mindful that the ability of a very small utility such as TOMBEU to defer the recovery of revenue will be limited by its financial circumstances and its ability to finance the deferral. While Mr. Heide did not believe a phasing-in of the rate increases would be impossible, he certainly identified some challenges. If the utility finds that it becomes impossible to manage the deferral, it should immediately apply to the Board for relief.

3.5.6 Pole Attachment Charge

[141] TOMBEU requested approval of an increase in the rate it charges to telecommunications carriers to attach their equipment to poles owned by TOMBEU. The proposed charge of $22 amounts to an increase of $7.85 or nearly 55%.

[142] For years, TOMBEU maintained a pole attachment charge of $14.15, the same rate in NS Power's Regulations dated January 1, 2019. TOMBEU explained that it aligned its proposal for the fee increase with the pole attachment fee negotiated in the settlement agreement proposed between NS Power and communications companies

in *NS Power 2023-2024 Rate Application*, for the rate of $22.00 per year with annual cost escalations of 2%.

[143] TOMBEU did not carry out a Pole Attachment Fee Study. Instead, it asked its consultants, BDR, to review the results of pole attachment studies carried out by other utilities. BDR reviewed approved charges for utilities in Ontario, New Brunswick, and looked at NS Power's most recent proposal in its GRA in 2022. BDR noted that NS Power's initial proposal included a pole attachment fee of $37.71, based on a fee study. BDR's fee study review showed that studies had supported fees between $37 and $53 for other Canadian utilities. BDR believes that a study for TOMBEU would likely support pole attachment fees higher than $22 per year. TOMBEU attempted to balance reasonable compensation for its customers for the use of poles that are part of rate base, and an acceptable rate for Nova Scotia communications utilities. The utility would prefer to apply the same rate used by NS Power to maintain consistency in pole attachment fees across the province.

[144] TOMBEU did not include the additional revenue from the pole attachment charge increase in the test year in the Rate Study. In Undertaking U-5, TOMBEU noted it services 613 poles, resulting in additional revenue of $4,812. TOMBEU indicated that, assuming no other changes to the original filling, the rate increase would be reduced from 34.2% to 33.9% if the additional revenue was included in the test year.

3.5.6.1 Findings

[145] The Board observes there were no interventions or challenges to TOMBEU's proposed pole attachment charge. The current charge has been in effect

since at least 2010 and the evidence indicates that the utility is not recovering its costs from the current fee level.

[146] Shortly before the hearing in this matter, the Board released its decision in *NS Power 2023-2024 Rate Application* and approved the proposal for NS Power's pole attachment charge of $22.00. The Board is satisfied that the proposed pole attachment charge represents a fair and reasonable estimate.

[147] The Board approves the pole attachment charge of $22 per pole/per year, and the related amendment to Schedule B – Schedule of Rules and Regulations (Regulation 11). The Board directs the utility to include the impact of the new rates in the test year revenue in the compliance filing.

3.6 Deferral of Nova Scotia Power Costs

[148] TOMBEU's application requested approval to maintain a deferral account for any liability associated with power purchases from NS Power commencing January 1, 2023, for which NS Power has received or may receive approval from the Board to recover from TOMBEU in a period after the purchases were made. TOMBEU advised that if balances accumulated in this deferral, it would apply to the Board for recovery through rates or rate riders on such terms as may be approved by the Board.

[149] TOMBEU provided additional details about this proposed deferral account in its response to Board IR-14 (Exhibit M-6). TOMBEU said it was concerned that if NS Power did not recover its revenue requirement in 2023 (and beyond), TOMBEU may be called upon at some future time beyond 2023 to pay the unrecovered 2023 shortfall in NS Power's revenue requirement. TOMBEU noted that it may or may not be

a customer of NS Power in the future period when it might be obliged to pay something to NS Power.

[150] TOMBEU also considered that the existing flow-through mechanisms in its tariffs would not serve the same function as its proposed deferral account. In response to Synapse IR-23(b) (Exhibit M-7), TOMBEU said the formula used in its flow-through applications is based on a two-year purchase history from NS Power and noted that it bought no energy except for back-up energy from NS Power in the past two years.

[151] In her evidence, Ms. Whited considered TOMBEU's proposal for a deferral account to be reasonable. She said increased purchased power costs from NS Power are both unknown and outside of TOMBEU's control. She added it was not apparent that the existing flow-through mechanism could be leveraged to address TOMBEU's concern. She recommended that the Board approve TOMBEU's proposed deferral but require the utility to apply for approval to recover any amounts accumulated in the account over a period to be determined by the Board.

3.6.1 Findings

[152] The only existing mechanism under which NS Power could seek the recovery of purchased power costs in a prior period from TOMBEU is NS Power's fuel adjustment mechanism (FAM). If TOMBEU remains a customer of NS Power in a future period when FAM adjustments occur, TOMBEU may be able to recover those amounts through its existing flow-through mechanism.

[153] The Board notes that the flow-through mechanism for DSM and FAM adjustments in TOMBEU's existing tariff is based on calculations using "KWH Purchases from NSPI for previous complete fiscal year." If there are FAM adjustments in 2024, it is

likely that NS Power would seek to implement those on January 1, 2024. Given that TOMBEU switched to the NS Power's Municipal Tariff on January 1, 2023, and is basing its rate increases on a calendar year test year, it may make sense to base TOMBEU's flow-through calculations on the calendar year, rather than its fiscal year; however, that is a matter that can best be addressed by TOMBEU in a flow-through application for 2024 if that is necessary.

[154] The Board recognizes that Section 3.1 of NS Power's current FAM Plan of Administration provides that fuel cost imbalances for a customer that transitions all or part of its load from a FAM class to a non-FAM class may be subject to adjustments occurring after the customer has departed. The Plan of Administration was not filed in this proceeding, but states:

> **3.1 Treatment of load migrating to non-FAM classes**
>
> When a customer transitions some or all of its load from a FAM-class to a non-FAM class, NS Power shall determine the customer's outstanding fuel cost imbalance at the date of transition. This determined imbalance will be adjusted in accordance with UARB decisions in subsequent FAM proceedings relating to the period in question (i.e. FAM AA/BA proceedings or a FAM Audit proceeding). The adjustments will be subject to UARB approval.
>
> The outstanding balance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB. Where payment is made over time, the transitioning customer shall pay, in addition, any carrying costs such that remaining customers and NS Power are kept whole.
>
> [M10431, Exhibit N-24, OE-01R Attachment 1, p. 11]

[155] If, in the future, TOMBEU is required to make such a payment under s. 3.1 of the Plan of Administration to NS Power (or any identical circumstances for DSM, if applicable), TOMBEU may include that payment in a regulatory deferral for later recovery from its customers upon application to the Board. Since imbalances of this nature may also produce a credit, any payment received by TOMBEU from NS Power

must be similarly held in a regulatory account, and in such a case, TOMBEU is directed to apply to the Board to determine how the credit will be applied to benefit its customers.

[156] The use of a deferral account for adjustments other than these imbalances is too speculative at this point. A deferral to account for these hypothetical adjustments is denied. If NS Power applies for another mechanism under which other costs could be recovered from TOMBEU, then the Board expects that TOMBEU would receive notice before it is approved. TOMBEU could bring an application to the Board to address the matter at that time.

[157] Finally, the Board recognizes that TOMBEU's purchased power arrangements have become more complex than when the existing flow-through mechanisms in its tariffs were originally developed. When NS Power was TOMBEU's only supplier, the flow-through mechanisms provided an efficient means for TOMBEU to flow-through cost increases to its customers. In a more complex arrangement, where NS Power is only providing part of TOMBEU's supply, it is possible that increasing costs for the purchase of energy from NS Power may be offset by decreases from other suppliers. In such a case, the flowing through of cost increases from NS Power may not be appropriate.

[158] The Board directs TOMBEU, in its next GRA, to address whether, considering the recent complexity of its purchased power arrangements, the existing flow-through mechanisms should continue. As part of this, TOMBEU may wish to consider, on its own or in consultation with one or more other municipal electric utilities, whether another mechanism should be developed to facilitate a timely and fair recovery of purchased power costs. A purchased power adjustment mechanism that would only pass

along actual purchased power costs to TOMBEU's customers could be such a mechanism, although it would necessarily entail robust tracking and auditing processes that would place an increased administrative burden on the utility.

3.7 Future Studies and Proceedings

[159] An underlying theme in this hearing was a clear lack of studies, analysis and data that is specific to TOMBEU. Clearly, the dearth of such information presents a challenge to TOMBEU in making key decisions around its operations, its cost-of-service, and its rate structure. At the same time, it is evident that, as a small utility, TOMBEU does not have the underlying staff and financial capacity to easily remedy this situation.

[160] There were additional factors in this case that made the situation worse. First, records that would have been useful to develop better assumptions around things such as load forecasts were not available because they were disposed of under the Town's records management policy. It does not appear the specific data requirements for the utility were considered under this policy or that a longer period may be required for utility records because the utility's last GRA was 15 years ago. Second, although TOMBEU gathered additional data about hourly load profiles because of a direction in its last GRA, that information was not used in this proceeding. TOMBEU's consultants said at the hearing that they would have used this information if it had been provided. Mr. Heide could not explain why this information was not provided to TOMBEU's consultants but believed that staff may not have been aware of it due to turnover.

[161] TOMBEU emphasized several areas for further review or study at this point, including:

- "…the recommendation by the Board's consultant to file a proposal within the next 18 months to enhance the data and analysis used to develop cost allocation factors and rates" (Final Argument of TOMBEU, p. 10);
- "…the recommendations to review the existing declining block rate structure." (Final Argument of TOMBEU, p. 10); and
- "… to review the time of use rate designs from other utilities and obtain expert advice on whether the time of day pricing would continue to be something that TOMBEU is interested in providing. In response to U-2, TOMBEU confirmed that, if so ordered by the Board, the results of such a study could be filed within 6 months of the order to do so." (Final Argument of TOMBEU, pp. 10-11)

3.7.1 Findings

[162] While the Board prefers stronger supporting research for TOMBEU's rates, it understands there are limits to how much can be accomplished and how quickly. The Board understands that work such as this must be prioritized and staggered over a longer period.

[163] The Board understands that the Town intends to revise its records management policies to address TOMBEU's data needs. The Town also noted it had taken steps to put a larger structure in place to support the utility, with more capacity and better records administration. The Board appreciates the Town's efforts in this area and is satisfied these steps should help to minimize information gaps in future proceedings.

[164] The Board is also encouraged to see the level of cooperation that exists between TOMBEU, RELC and some of the other small utilities in the province, as well as the role played by AREA, including the possibility of training and mentorship, as mentioned in the RELC GRA hearing [2023 NSUARB 56]. Such cooperation could help reduce the pressure on TOMBEU to produce its own specific analysis and studies. The Board would encourage such further cooperation and would welcome studies and analysis that are specific to not only TOMBEU, but the larger community of small utilities.

[165] The Board directs TOMBEU, at its next GRA or within 24 months, to identify which formal studies it has or expects to undertake and the status of any joint training or research activities undertaken or planned with the other municipal utilities or AREA.

4.0 SUMMARY

[166] The Board approves the proposed changes to TOMBEU's Schedule of Rates for Electric Supply and Service and its Schedule of Rules and Regulations Governing the Supply of Electric Services, effective the date of this decision, subject to the following:

- TOMBEU must revise its revenue requirement to account for:
    - reduced power purchase costs from NS Power's approved rates;
    - removal of the proposed $15,000 for storm restoration;
    - the recovery of the revised estimate for the costs of this application, amounting to $41,050 in the test year;
    - revenue from pole attachment fees based on the charge approved in this decision;
    - updated working capital based on 12% of the net cash expense after all the adjustments required by this decision; and
    - a return on equity of 7.5%.
- TOMBEU's proposed rates are to incorporate the following cost-of-service, rate design and other changes:
    - classify transformer costs as 100% demand-related;
    - include meter costs in computing the ratio of classified distribution plant;
    - correct the weather-normalization error in its load forecast;

- base customer service charges for the Domestic class on costs classified as customer-related in the cost-of-service study;

- correct the classification error that resulted in $60,644 being incorrectly posted to street lighting, when it should have been posted to distribution systems;

- update the DSM charges in the revenue requirements based on NS Power's rates approved February 2, 2023, and include in existing charges rather than as a separate rider;

- adjust the rates for the Street Light class by 1.25 times the system-wide average change; and,

- other than Domestic Service Time-of-Day and Net-metering, rates are to be adjusted equally if the result would not produce rates that are within a 90% to 110% range. If there are classes outside of this range (aside from Street Lights), they must be capped at the top of the range or increased to the bottom of the range, with any resulting excess or shortfall redistributed to classes within that range to the limits of the range.

- TOMBEU's rate increases in 2023 are to be capped at 20% for each rate class, with rates being fully applied effective January 1, 2024, and with any unrecovered revenue from 2023 to be deferred for future recovery, upon application to the Board, beginning January 1, 2025 or as otherwise directed; and

- The Board has not approved TOMBEU's requested deferral account for potential future liabilities, but approves the establishment of a deferral account with a more limited scope.

[167] TOMBEU is directed to file a compliance filing, no later than May 12, 2023, to address the changes to its application required by this decision. The compliance filing must include an updated version of Exhibit M-5 (all exhibits) and Exhibit M-1 (Exhibit 7), and a clean and redlined version of the utility's new tariffs and regulations.

[168] TOMBEU is further directed as follows:

- To establish a sub-account for storm recovery costs and track them through its existing accounting software, or in a spreadsheet if this cannot be done through its accounting system;
- To review whether maintaining the second block rate can be justified from a cost perspective, and return to the Board with the results of its analysis in a future GRA; and
- To identify, at its next GRA or within 24 months, which formal studies it has or expects to undertake and the status of any joint training or research activities undertaken or planned with the other municipal utilities or AREA.

[169] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 28th day of April, 2023.

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Stephen T. McGrath

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Bruce H. Fisher