SPECIAL TOWN COUNCIL AGENDA
October 21, 2022
9:00 a.m.
Council Chambers

Let us begin by acknowledging that we are gathered today in Mi'kma'ki. The ancestral, present and future territory of the Mi'kmaw people. Today, we gather with the intent followed by the living Peace and Friendship Treaties - with respect, cooperation and coexistence.

Call to Order

1 Approval of Agenda

2 Reports
2.1 Easement Valuation Report – Turner Drake
2.2 Electrical Utility Rate Study and Application - BDR

3. Plan Mahone Bay
3.1 Plan Mahone Bay Steering Team Process

THE TOWN OF MAHONE BAY ELECTRIC COMMISSION

RATE STUDY

October 21 DRAFT, 2022

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Table of Contents

1 Tab A – Introduction and Administrative Matters

1.1 Background Information about the Applicant

The Town of Mahone Bay Electric Utility (“ToMBEU” or the “Utility”) is a distributing utility, supplying electricity service in the Town of Mahone Bay (the “Town”) and vicinity. The Utility serves approximately 835 metered Domestic and non-Domestic customers, as well as unmetered lighting services.

TOMBEU currently operates with staff who are employees of the Town, and also shares two full-time powerline technicians and one full-time apprentice, with the Riverport Electric Light Commission (RELC) Utility on a 50% basis. The cost-sharing arrangement allows TOMBEU to have dedicated qualified staff for the operation of its distribution system, despite the small size of the utility.

Wholesale electricity supply is purchased under multiple contracts with third parties, which are reviewed regularly in order to obtain the best available pricing for the benefit of TOMBEU’s customers. TOMBEU does not own or operate any electricity generation. The system peak for the Calendar Year 2023 is forecast at 3,691 kW on a weather-normalized basis.

The customer base forecast for the Calendar year 2023 consists of 685 Domestic, 76 Small General Service, 69 General Service Customers, 12 Time of Day Customers and 3 Net Metering Customers.

In recent years, TOMBEU has experienced modest growth in its customer base and total energy served.

1.2 Need for Rate Increase at this Time

TOMBEU’s last Application for changes to its rates and charges, other than flow-through of changes in the cost of purchased power and the addition of rates for LED street and yard lighting, was decided by the Board April 18, 2008. Since then, rates have been adjusted in accordance with the flow-through methodology to reflect increases in the cost of purchased power. The current rates came into effect on January 1, 2019. TOMBEU has been able to continue without increases to its Board-approved distribution revenue requirement because of a combination of tight management of operating costs and postponement of investments in its distribution system, other than those directly applicable to connection of new loads and therefore funded in whole or part through contributions in aid of construction.

The Utility’s capital plan for the current fiscal year includes $336,000 in spending, of which the most significant items are:

- Continuation of a multi-year program to replace lines and poles as well as transformers with PCBs;
- Purchase of a new truck; and
- Purchase of a new wood chipper, to be shared with Riverport Electric Light Commission.

In the Test Year, the Utility's capital budget is $145,000, of which the major item is continuation of its replacement program for lines, poles, and transformers with PCBs.

All of these projects are considered to be urgently required to maintain reliability and safety.

In addition to the challenge of funding this capital budget, TOMBEU, like every organization in the current economy, is faced with increasing cost of various supplies and services.

As a result, through AREA, TOMBEU commenced the process of preparation of this Rate Study with a view to making a General Rate Application to the Board.

Recently, in a context of serious escalation of fuel prices in the world markets, AREA, on behalf of TOMBEU, entered into negotiation for new contracts for its wholesale supply of electricity. After evaluating several alternatives, the decision was made to enter into a one-year contract with Nova Scotia Power to purchase supply at the rate for municipal customers approved by the Board. TOMBEU has estimated, based on the contract rates, the costs of its other power supplies, and forecast loads, that on an annualized basis per kWh its cost of purchased power will increase by 37.2% in the Test Year over the 12-month period, and is concerned that it will continue to increase by a further unknown but significant amount in the year or years following the Test Year.

The Utility projects that it will realize an operating loss of $20,000 in the current financial year, and would realize a loss of more than $600,000 in the test year at current rates.

With all of these factors in combination, TOMBEU has concluded that it cannot continue to provide service at the currently approved rates without severe detriment to its financial integrity.

1.3 Approvals Being Requested in this Application

TOMBEU hereby requests approval from the Board of the following:

- Approval of calendar 2023 as the Test Year, to enable new rates approved effective January 1, 2023 to meet the revenue requirement for a forecast calendar year;
- Approval of the Revenue Requirement of $ 2,813,708 for the Test Year, comprised of the costs shown in Exhibit 5.
- Approval to accrue into the Test Year all incurred and budgeted costs for advisors, legal counsel and costs of the Board related to this Application, and recover such costs in the Test Year.
- Approval to maintain a deferral account to reflect any liability associated with power purchases from Nova Scotia Power commencing January 1, 2023, for which Nova Scotia Power has received or may receive approval from the Board to recover from TOMBEU, in respect of power purchased by TOMBEU in and beyond the Test Year. If balances accumulate in this deferral account, TOMBEU would at some later date apply to the Board for approval to recover such balances through rates or rate riders upon such terms as may be approved by the Board.
- Approval of the Schedule of Rates and Charges as proposed in Tab I of this Rate Study, 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.
- Approval of the Schedule of Rules and Regulations Governing the Supply of Electric Services included in Tab J of this Rate Study.

1.4 Organization of this Rate Study

This Evidence is organized around the sequence of analysis leading to TOMBEU's proposal for a 2023 Revenue Requirement, allocation of the Revenue Requirement to customer classes, and proposal for rates to recover the Revenue Requirement from customers.

The current Tab A introduces some facts about TOMBEU's service territory, scope of operations, staffing, and sets out the main factors which have made it crucial for TOMBEU to request immediate rate relief.

Tab B presents TOMBEU's asset base for recent historic years and for the Test Year, which TOMBEU is proposing to be the Calendar year 2023. Use of a calendar test year would, if the Board approves new rates effective January 1, 2023, align a full year of revenue at the new rates with forecast loads and costs. This Tab includes discussion of the capital expenditures TOMBEU believes to be crucial in the Test Year and following years.

Tab B also addresses TOMBEU's requested working capital allowance as a component of its Rate Base.

Tab C sets out TOMBEU's proposed rate of return on rate base.

Tab D details the approach, methodology and results of TOMBEU's load forecast for the Test Year.

Tab E provides historic, current and Test Year operating revenues and expenses, and details the key factors responsible for the higher costs TOMBEU expects to experience in the Test Year.

Tab F provides computations of the Revenue Requirement, based on the operating expenses and return on rate base, and computes the additional revenue that TOMBEU will need to cover the costs of service in the Test Year.

Tab G explains the methodology used to allocate the Revenue Requirement to customer classes, and provides detailed computations.

Tab H explains TOMBEU's proposals for rate adjustments for the Test Year, and demonstrates that the proposed rates will permit TOMBEU to recover its Revenue Requirement assuming the budgeted level of expenditures and sales as forecast on a weather normalized basis.

Tab I provides a draft of TOMBEU's rate schedule for the Test Year, subject to approval by the Board, and Tab J is TOMBEU's Rules and Regulations. TOMBEU is still in the process of completing its proposals for several changes to its Rules and Regulations.

In order to expedite submission of this Application, TOMBEU requests permission to file a revised Tab J at a later date.

2 Tab B – Rate Base

TOMBEU's rate base for the Test Year is supported by Exhibits 1-1 (Gross Plant) and 1-2 (Net Plant). Each of these schedules shows plant balances for the financial years ended March 31, 2020, 2021 and

2022, which are on an actual basis, a budget for the financial year ending March 31, 2023, and a budget for the Calendar Year 2023 (ending December 31, 2023).

A review of these schedules shows that in recent years, the Utility is carrying out a modest program to perform needed replacement work on its distribution system, and to acquire needed transportation and other equipment shared, where efficient to do so, with a neighbour utility. After the Test Year, the Utility expects to be able to continue with a capital budget of less than $50,000 per year.

TOMBEU submits that the planned capital expenditures are necessary for the continued safe and reliable operation of its distribution system and supply of its customer base.

Exhibit 1-2 also shows the budgeted amortization expenses for the current 2022/23 year ($61,853) and the 2023 Calendar Test Year ($62,791), distributed to asset classes to enable appropriate allocation of costs. Most of TOMBEU's distribution assets are amortized over a life of 30 years.

TOMBEU is proposing a Test Year rate base that includes a December 31, 2023 budgeted net plant balance of $ 1,682,982.

In addition, TOMBEU requests approval of a working capital allowance of $ $318,104. This allowance is based on an estimated 43 days' payment lag (12%) applied to its forecast $ 2,650,863 in net cash expenses (cost of purchased power and operations, maintenance and administrative costs, but excluding amortization expense). The computation of this proposed allowance is shown on Exhibit 3. TOMBEU has chosen not to include a further allowance for inventory at this time.

On this basis, TOMBEU is requesting the Board's approval of a rate base of $ 2,001,085 for the Test Year. The computation is shown at the bottom of Exhibit 1-2.

3 Tab C – Rate of Return

TOMBEU is requesting the Board's approval of a rate of return on its rate base of five percent (5%). This is calculated based on deemed capital structure of 60% debt and 40% equity, which is near the structure that NSPI has proposed, and is also the structure that has been considered reasonable for small distribution utilities elsewhere in Canada.

TOMBEU estimates its cost of debt at three percent (3%). TOMBEU proposes a rate of return on the proposed 40% equity component of the capital structure of eight percent (8%). These computations result in a weighted average cost of capital of five percent (5%).

A return of 5% applied to rate base of $ 2,001,085 is calculated in Exhibit 1-2 at $ $100,054. This amount would recover interest on TOMBEU's existing small debt balance and allow TOMBEU the opportunity to earn a net income of $ $99,554. The calculation of these figures is shown in Exhibit 3.

4 Tab D – Load Forecast

4.1 Forecast Methodology

In the absence of prior analysis, a forecast methodology was developed for this Application.

Data was collected for number of customers and monthly kWh consumption for each customer class of TOMBEU on an actual basis for the years 2015 through August 2022. Older data prior to 2015 is not available. Data was also obtained for heating degree days ("HDD") and cooling degree days ("CDD") for the same historic period. TOMBEU understands that although historically many utilities have used 30-year historic averages to reflect "normal" weather, more recently there has been a move to use 10-year data in order to better reflect the recent trend to warmer temperatures. A review of information filed by NSPI showed that NSPI used 10 years of weather data for the load forecasts in its 2022 application[1]. For the purpose of this load forecast TOMBEU has used the seven full years of historic data available from 2015 to 2021, and the part year through August 2022. Going forward as new data becomes available TOMBEU will plan to use a 10-year weather data time horizon in anticipation this would be acceptable to the Board in its case also.

Based on review of the material, TOMBEU understands that for its Domestic forecast, NSPI uses as input variables the annual heating degree days, economic variables and appliance saturation data. There is no mention as to whether cooling degree days are considered. TOMBEU does not have economic or appliance data specific to its service territory, and has no information on which to conclude whether province-wide data would be appropriate to its service territory. Therefore, the Domestic sales forecast for TOMBEU is based on HDD data for weather normalization and observed trends in TOMBEU's own customer base and per-customer consumption.

Per-customer consumption was weather-normalized for the historic period, incorporating an observed slight downward trend in HDD over the historic period to allow the trend in consumption to be observed.

Like NSPI, TOMBEU has computed the total forecast of Domestic sales as the product of a forecast number of customers and a forecast of consumption per customer on the basis of normal (heating) weather.

For the forecast of non-Domestic customers and loads, TOMBEU observed a weather sensitive trend to consumption and has therefore used HDD data for weather normalization and observed consumption trends and knowledge of its customer base to forecast for the Test Year. TOMBEU submits this approach is more specific and relevant than the alternative, which is to assume that province-wide economic and business factors will be reflected uniformly in TOMBEU's service territory. Loads were weather normalized for the Small General Service class, General Service class, and both the Time of Day and Net Metering customer classes.

For unmetered loads, the number of connections was included from TOMBEU records. A majority of the streetlight and yard light currently installed are 53-Watt LED lights (~80%), with the remaining light

[1] 2022-2024 GRA Direct Evidence Appendix 3A Load Forecast Details

fixtures ranging from 30 - 150 watts. Lights are assumed to operate at 46% load factor (4,000 hours per year).

For the General Service class, a forecast of monthly kW sales was required for purposes of forecasting revenue on the basis of existing and proposed new rates for the test year. For this purpose, history of monthly load factors was analyzed. It was found that sales load factors are in the range of 28% to 36%. On this basis, total monthly kW for kW-metered customers is forecast at 1,565.5 kW per month on average.

All sales kWh forecasts were escalated to adjust for distribution losses at a factor of 4.1% to produce a forecast for aggregate power purchases.

As of January 1, 2023, TOMBEU power purchases will include supply from Nova Scotia Power Incorporated (NSPI) using the Municipal Tariff which includes both an energy ($/kWh) and demand ($/kW) rate component. The NSPI Municipal Tariff demand charge is calculated based on the maximum winter peak demand (winter includes the months of December, January and February) incurred in the current month or previous 11 months. The demand for the three winter months has been forecast using the average actual load factors for the most recent 5 winter months (Jan, Feb and Dec 2021, Jan, Feb 2022). The average actual load factor of 61% was then applied to the forecast energy to determine the demand in that month. The NSPI demand charge is then calculated using the maximum forecast demand for the current month or previous eleven months as already described above.

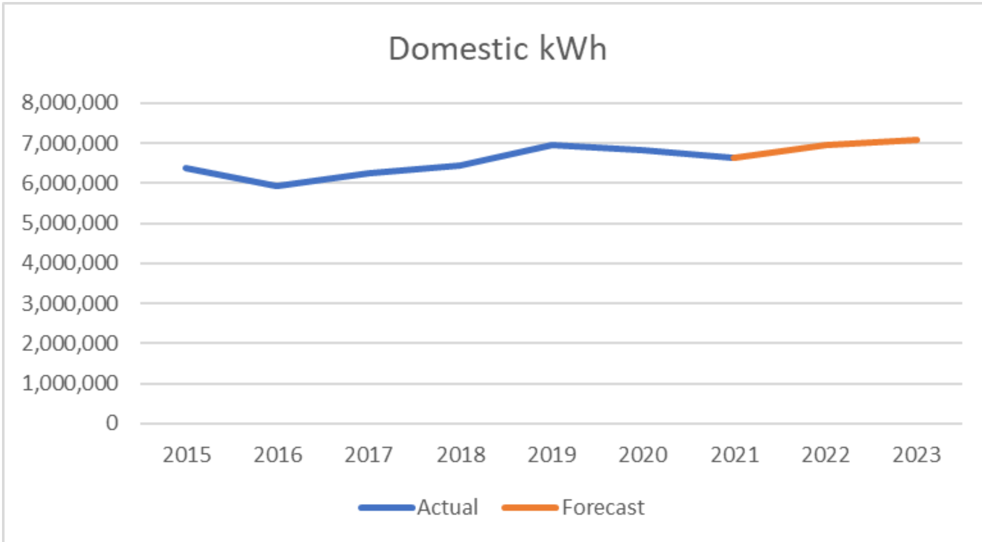
4.2 Forecast Results

4.2.1 Domestic

The number of TOMBEU's Domestic customers has shown a consistent gradual upward trend, growing from 617 customers in 2015 to 667 customers in 2021 (average for the year). The compound annual growth rate is 1.32%. The Town of Mahone Bay has issued 5 building permits to date in 2022 and anticipates a small number of additional housing units in 2022 and 2023. The forecast for the Test Year has therefore assumed a continuation of this trend, bringing the number of Domestic customers to 683.

As noted also by NSPI for its own retail loads, TOMBEU observed a modest increase in normalized per-customer usage starting in 2016, which has been consistent since that time, and accepts the conclusion of NSPI that this reflects an increasing use of electric space heating. As a result, only the years 2017 through 2021 have been considered in determining a growth factor for Domestic consumption per customer. The average of the prior non-pandemic years has been used as the base in applying growth, as a proxy for an explicit adjustment for work at home during the pandemic. This results in a forecast of 10,329 kWh per customer for 2022 and 10,372 per customer for 2023.

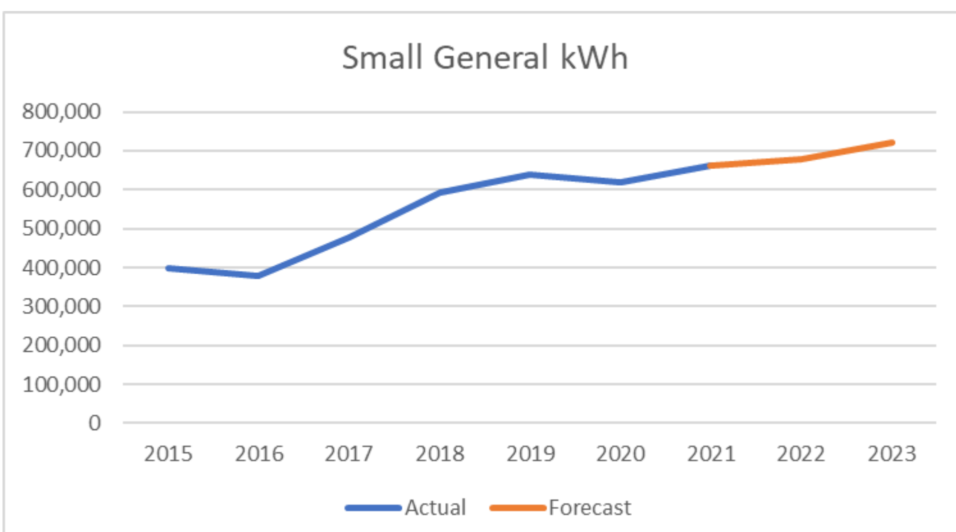
The following graph shows historic and forecast kWh sales for the Domestic class.



4.2.2 Small General Service

The Small General Service customer base has grown from 68 customers in 2015 to 77 customers in 2021. While there has been a loss of two customers to 75 in 2022, TOMBEU expects that its Small General customer base will continue to grow in the future as it has in the past. The compound customer growth rate from 2015 to 2021 of 2.16% has therefore been used to forecast the number of customers at 76 in 2023 from 75 in 2022.

A review of the actual 7-year per customer consumption data from 2015 to 2021 shows a robust increase of 6.5% per year on average. Based on a 7-year linear regression of weather normalized usage, the forecast consumption per customer is 9,101 kWh and 9,470kWh in 2022 and 2023. The historic and forecast kWh sales for the Small General rate class is presented in the graph below.

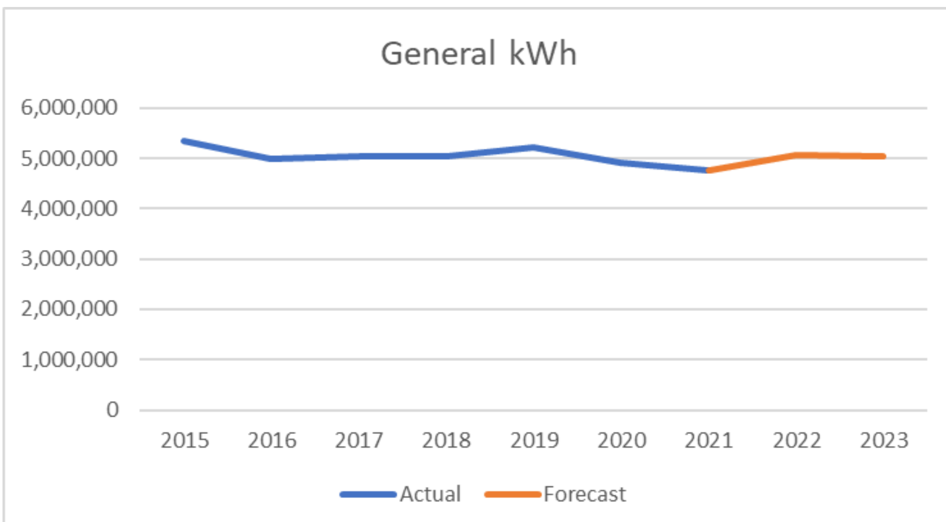


4.2.3 General Service

The General Class customer base of TOMBEU remained consistent at about 66-67 customers between 2015 and 2021. This customer number has remained relatively consistent through 2015-2021, which included a challenging economic environment due to the pandemic.

There have been two new customers to date in 2022, and a third customer is scheduled for the 4th quarter of 2023. TOMBEU is forecasting an average of 69 customers in both 2022 and 2023.

A review of the historical per customer consumption over the seven-year period from 2015 to 2021 shows an average annual decrease of 1.9%. Based on a linear regression of weather normalized usage, the forecast consumption per customer is 73,236 kWh and 72,658 kWh in 2022 and 2023. The graph below presents the historic and forecast total kWh sales for the General rate class.



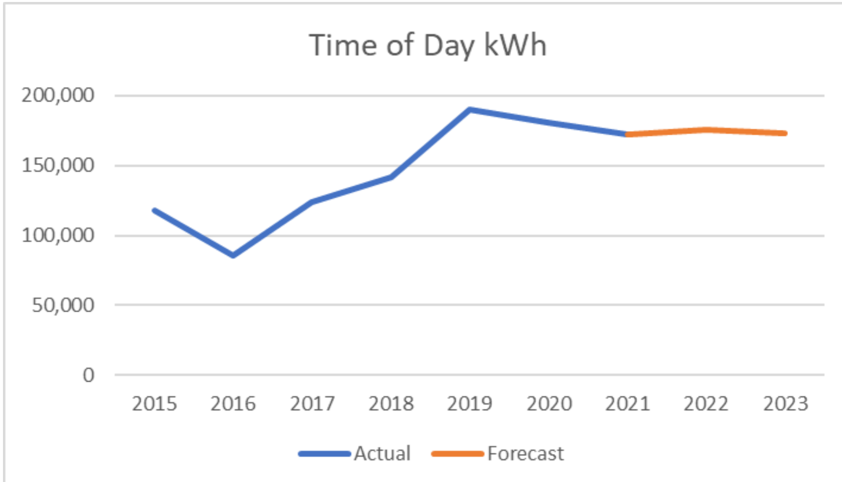
The per customer demand forecast for billing is based on the average historical demand in the past two years for the same month. The forecast maximum monthly per customer demand is 24.3 kW for 2022 and 27.0 kW for 2023.

4.2.4 Time of Day Service Class

The Time of Day service class is was first offered in 2012 as an option for domestic customers. The number of customers has increased slowly from 5 to 12 from 2012 to 2019, and is unchanged through 2021. TOMBEU is forecasting the number of customers to remain unchanged at 12 customers for 2022 and 2023.

The actual per customer consumption annual growth from 2018 to 2021 has remained virtually flat (0.1% growth). Applying a linear regression on the weather normalized usage results in a forecast of

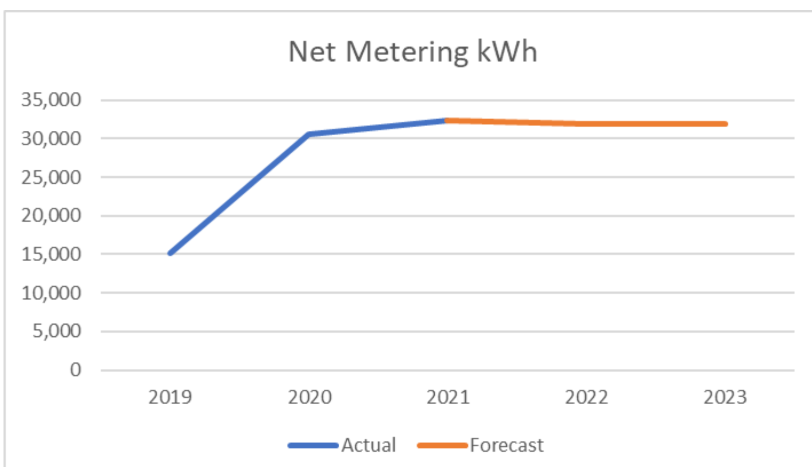
14,594 kWh and 14,405 kWh for 2022 and 2023 respectively. On this basis, the consumption forecast for this customer class is based on the average of the actual load from April 2021 to July 2022 for both energy and demand. The forecast energy is 163,920 kWh and peak monthly sales demand is 79.6 kW for both 2022 and 2023. The actual and forecast sales (kWh) is presented in the graph below.



4.2.5 Net Metering Service Class

Net Metering Service class was first offered in 2019 and has grown from 2 customers in that first year to 3 customers for 2020 and 2021. TOMBEU is forecasting 3 customers for 2022 and 2023.

Given the limited number of years historical data and the small number of customers, TOMBEU is forecasting the per customer sales for 2022 and 2023 to be equal to the historical average for 2020 and 2021 of 10,653.2 kWh. The Net Metering sales (kWh) is presented in the graph below.



4.2.6 Unmetered Load Forecast

Unmetered consumption includes street lighting and yard lighting. The forecast for each type of unmetered load is based on the number of fixtures/ units, wattage and hours of operation. The forecast load for 2023 is summarized in the table below.

	Watts	Fixtures	Hours	Energy kWh
Street Lights	50	17	4,000	3,400
	83	43	4,000	14,276
	53	211	4,000	44,732
				62,408
Yard Lights	150	1	4,000	600
	60	2	4,000	480
	53	43	4,000	9,116
	30	2	4,000	240
	129	4	4,000	2,064
				12,500
Total Unmeter Sales - kWh				**74,908**

4.3 Summary of Forecast of Sales and Purchases

This table shows the billing determinants actual and forecast for each of the customer classes.

	Actual	Forecast	Test Year
Customers	**2021**	**2022**	**2023**
Domestic	667	674	683
Small General Service	77	75	76
General Service	67	69	69
Time of Day	12	12	12
Net Metering	3	3	3
Street Lighting	271	271	271
Yard Lighting	52	52	52
Cable Unmetered	0	0	0
	1149	1156	1166
Energy kWh			
Domestic	6,634,291	6,961,882	7,082,334
Small General Service	662,268	678,030	720,808
General Service	4,762,463	5,053,258	5,029,515
Time of Day	171,685	175,128	172,866
Net Metering	32,345	31,960	31,960
Street Lighting	62,408	62,408	62,408
Yard Lighting	12,500	12,500	12,500
	12,337,960	12,975,165	13,112,391
Demand kW (per customer for billing)			
General Service	28.7	24.3	28.2

The table below shows the estimated demand of each customer class at TOMBEU's system coincident peak, for the test year. Coincident peak responsibility is used in the allocation of the demand-related component of the cost of purchased power. The Utility does not have metered data necessary to establish class or customer demands at the time of system peak.

Coincident Peak (CP) Demand - kW	Test Year 2023
Domestic	2,086.3
Small General Service	202.2
General Service	1,337.7
Time of Day	44.4
Net Metering	9.4
Street Lighting	10.1
Yard Lighting	2.0
TOTAL	**3,692**

5 Tab E Operating Revenues and Expenses, including Purchased Power

5.1 Electricity Revenues

TOMBEU is forecasting Test Year revenues for sale of electricity at $ 2,061,533 from its Domestic, Small General Service, and General Service metered customers, and its unmetered Street Light, and Yard Lighting loads. These amounts are determined by applying TOMBEU's existing rates to the forecast billing determinants in the Test Year for each class. These amounts are shown as line items in Exhibit 3. The forecast is a revenue increase of three percent (1.2%) as compared with the financial year ending March 31, 2023, reflecting a change in consumption levels.

5.2 Other Revenues

In addition, TOMBEU forecasts that it would receive a total of $ 34,880 in cash revenues from other fees and charges.

5.3 Purchased Power

Purchased power expense has been forecast by applying the rates at which TOMBEU anticipates purchasing in the Test Year to the forecast of weather-normalized electricity purchases to serve its customers, including losses at 4.1%. Supply will be purchased from NSPI at the Board-approved rate for municipal utility customers, for all needs surplus to supply available from a separate wind contract. For the forecast, TOMBEU has used the best available information as the NSPI's rates at that time. Purchased power represents the most significant component of TOMBEU's increased revenue requirement for the Test Year, as compared with the current year. It is the largest component of TOMBEU's total cost, and is forecast to increase by forty percent (41%). AREA, which procures supply for TOMBEU as well as other Nova Scotia distribution utilities, negotiated for imported supply before recommending purchase from NSPI for the Test Year. TOMBEU believes that the supply arrangement with NSPI represents the best alternative available for its customers in terms of both price and security of supply for the Test Year.

5.4 Operations and Maintenance Expenses

TOMBEU shares staff and certain equipment with the Town of Mahone Bay in order to benefit from economies of scale in providing quality 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 or storm restoration is required in any particular year.

As a result of considerations raised by the recent hurricane in Nova Scotia, TOMBEU has reviewed operations and maintenance spending plans to determine if its budget for the Test Year is adequate to cover a small provision for storm restoration. While significant storm restoration costs are not incurred every year, they are both certain in the long term and uncertain as to the time of occurrence. TOMBEU estimates that restoration from a major weather event would result in costs in the $60,000 to $90,000 range, and occur on average every 4-6 years. Therefore, an allowance in each annual budget of $15,000 would allow the costs to be absorbed when they occur, except in the most extraordinary cases, without necessity for an application to recover storm expenses after the fact, and be stable in terms of impact on customers. TOMBEU understands that NSPI has a similar policy with respect to budgeting for the impacts of weather events. The Utility considers that the total distribution operations and maintenance budget of $ 360,046 is adequate to include such a provision in the Test Year.

5.5 Administrative and General Expenses

For the Test Year, TOMBEU is forecasting that it can operate at the same level of cost as for the current year, despite price escalation generally in the economy. The increase in budget for administrative cost in the Test Year, compared with the current year reflects a provision for the costs of this application for rate adjustment to the Board.

5.6 Amortization Expenses

Amortization expenses have been estimated by applying TOMBEU's amortization rates to the existing and forecast new assets in rate base.

5.7 Interest on Long Term Debt

TOMBEU's budget for interest on long term debt includes $500 in respect of a small loan balance currently outstanding.

6 Tab F – Revenue Requirement and Requested Rate Increase

TOMBEU's total revenue requirement for the Test Year is proposed at $ 2,813,708. This is computed from Exhibit 3 as the total of cost of purchased power, operations and maintenance costs, administrative and general costs, and amortization costs, plus $ 100,054 for return on rate base at 5%. The $ 100,054 would cover $500 in interest expense and provide a net income of $99,554.

At current rates, TOMBEU would in the Test Year realize an operating loss of $ 617,741. To realize a net operating income of $ $99,554 , TOMBEU therefore needs an increase in revenue of $617,741 + $99,554 = $ $717,296. As a percentage of the revenue at existing rates, this is an increase of 34 percent.

This amount would recover all of the currently forecast costs of the Test Year.

7 Tab G – Cost Allocation to Customer Classes

TOMBEU's allocation of costs to customer classes is set out in Exhibits 4-1, 4-2, 4-3, 4-4, 4-5, and 4-6 and summarized as ratios of revenue to cost in Exhibit 5.

The study proceeds in three stages for each type of cost: functionalization, classification and allocation. TOMBEU, as a distribution utility, has no generation or transmission cost functions. It has its costs of purchased power and distribution functions. For more accuracy in classification and allocation, distribution costs are functionalized in greater detail, by breaking down into asset classes and service activities such as billing, metering and administration. In a few cases, costs can be directly identified as to the class that incurs them, and assigned to that class. Each cost function is classified as demand-related, energy-related or customer-related, or as a combination of those classifications.

Allocation factors are then applied to the classified costs, to distribute the costs to classes of customers. This cost allocation analysis applies widely used approaches combined with factors sourced from the forecast of billing determinants and estimates based on the judgment of TOMBEU management and its advisors.

Exhibit 4-1 shows the allocation factors used for different cost functions and classifications in the study. CP and NCP are estimates based on available billing data, assumptions as to the times of system peak and nature of the loads for each class. TOMBEU does not have hourly customer load data or load research, or a metered hourly system load shape.

Energy responsibility and number of customers are forecast data. Forecasts make use of historic records of the utility.

Weighted customer factors are based on the number of connections and judgment as to the cost of serving a connected load of each type.

TOMBEU's net plant consisting of distribution and general assets is shown functionalized into asset classes in Exhibit 1-2. Exhibit 4-2 classifies and allocates these assets to customer classes. Distribution assets are classified as either demand-related or customer-related in the portion of the exhibit labeled "Distribution Analysis". The classification factors are consistent with those previously used by TOMBEU in its 2008 application for general rate adjustments. This portion of the analysis calculates a summary distribution classification percentage that is used in the top portion of the Exhibit to classify general asset functions. Meters are classified entirely as customer-related. No component of distribution rate base is classified as energy-related.

The weighted net plant classification factor is then used to classify the working capital component of rate base.

The classified rate base is then allocated to customer classes using the appropriate factors from Exhibit 4-1. The demand component of the cost is allocated using non-coincident peak demand, and the customer component is allocated using number of customers, weighted to reflect differences in cost related to the class of customer. Identified street lighting costs are assigned directly to that class.

Exhibit 4-2 also shows the calculation of the aggregate allocation factor for rate base, and the allocations of vehicles and of poles and fixtures. These factors are then used in the study to allocate causally-related components of the revenue requirement, or of revenues.

Exhibit 4-3 applies the same methodology and factors to the classification and allocation of amortization costs, as was used for the assets.

Exhibit 4-4 shows the classification and allocation of purchased power, operating and maintenance expenses and administrative expenses. The amounts of each of these expenses come from Exhibit 3.

Purchased power has both a demand component and an energy component, flowing from the charge structures under which TOMBEU anticipates purchasing power in the Test Year. There is no customer (fixed or basic) component associated with these charge structures. The components shown as demand and energy related have been computed by applying the suppliers' rates to the forecast purchases of TOMBEU in the Test Year.

Distribution operations and maintenance costs for all assets other than meters are classified using the percentage classification for distribution assets other than meters in Exhibit 4-2. Costs associated with meters, and with billing, are classified as 100% customer-related, since number of customers is the driver of these costs. The classification of total rate base from Exhibit 4-2 is used to classify administrative and general costs. A derived factor is necessary for this cost, since administrative and general costs are not directly related to number of customers, their demands or their total energy use.

Each classified cost function is allocated to customer classes using the methodology noted in the lower part of Exhibit 4-4.

In Exhibit 4-5, financial costs including both interest on long term debt and net income are allocated to customer classes based on the allocation factor for the total rate base.   This reflects the relationship between rate base and the allowed return included in the revenue requirement.

Having allocated all components of the revenue requirement to customer classes, there remains only to allocate revenue in order to be able to compute ratios of revenue to cost for each class. This is done in Exhibit 4-6.

Electricity sales revenue is identified in the accounts of TOMBEU to the customer classes, and thus can be directly assigned to each class.

Revenues from charges other than the electricity rates are allocated to the credit of each customer class, since these revenues reduce the requirement for revenue from electricity rates. Allocation factors have been selected on the basis of judgment as to a component of costs or revenues that is related. Late payment charges are applied to bills based on the billed amount; therefore this revenue is allocated in proportion to the billed revenues for each class. Other revenues are diverse and with no direct relationship to an individual cost function. Rate base was therefore used to allocate these revenues.

Ratios of revenue to cost at existing rates are calculated in Exhibit 5. Note that because the revenues at existing rates are not sufficient to recover costs, the total revenue is only 74.5% of costs. All revenue/cost ratios for customer classes reflect this overall revenue insufficiency. All classes show over-recovery except for the net metering and time of use customers. Ratios for the unmetered classes are all well above 100%, indicating that if an equal rate increase were applied across all classes, these classes in particular would appear to be overcontributing to an undue degree.

Exhibit 6 recomputes revenue/cost ratios assuming rate increase are applied to recover the revenue insufficiency shown in Exhibit 5, and bring the overall utility revenue/cost ratio to 1:00 or 100%.

8 Tab H – Proposed Rates for the Test Year and Revenue Reconciliation

8.1 Rate Design

8.1.1 General Considerations

TOMBEU's current rates have been in effect since January 1, 2019. TOMBEU has not performed an in-depth review of rate designs for purposes of this Application, and proposes to continue the same methodologies pending future analysis and subject to any Order of the Board.

This Section details a small number of specific rate design considerations that are proposed in this Application.

8.1.2 Optional Domestic Time of Use Rates ("Domestic TOU")

The Time of Day service class is was first offered in 2012 as an option for domestic customers. The number of customers has increased slowly from 5 to 12 from 2012 to 2019, and is unchanged through 2021. TOMBEU is forecasting the number of customers to remain unchanged at 12 customers for 2022 and 2023.

This rate continues to be structured as originally approved by the Board, consisting of a base (fixed) monthly charge and energy charges for peak, shoulder and off-peak time periods. The rating periods consider time of day, day of week, and seasons, reflecting the load shape of a winter peaking utility. It is assumed with a high degree of confidence, but not verified by metered consumption data, that the off-peak rating period never coincides with TOMBEU's annual peak, and therefore consumption in this period does not cause demand-related costs, either for purchased power or on the distribution system.

The rate design approach in TOMBEU's approved Rate Schedules is as follows:

- On peak charges are twice the Total Regular Domestic 2nd Block kWh rate;
- Shoulder charges are equal to the Total Regular 2nd Block Domestic kWh rate;
- The off-peak charges are equal to the total purchase price per kWh from NSPI, plus losses.

In addition to the energy charges listed above, the structure includes a base rate charged monthly on a fixed basis.

As the Utility maintains separate records of the consumptions and revenues of time of day rate customers, it was possible to make allocations and determine a revenue/cost ratio. This appears to show that time of day customers have a lower revenue/cost ratio than other Domestic customers paying the standard rate. No analysis has currently been made as to whether this implies a rate design issue; however, it is noted that the off-peak rates are designed to contribute nothing to recovery of distribution costs.

In view of the very low take-up of this rate option after several years, and also in view of TOMBEU's small Domestic customer base overall, TOMBEU is not currently proposing to invest resources to review the appropriateness of the rate structure and methodology, and therefore requests the Board to approve continuation of the current rate design approach with respect to setting on-peak and shoulder kWh charges.

In view of the relatively low revenue/cost ratio of this class and the fact that the methodology for off-peak charges does not support recovery of distribution costs from that consumption, TOMBEU is proposing at this time to adjust the current off-peak charge by the same percentage applied to energy charges for regular Domestic Service.

8.1.3 Unmetered Street Light and Yard Lighting

Data and forecast for the unmetered lighting units are shown in Section 4.2.6. They reflect a gradual conversion to more efficient lighting over time.

The results of the cost allocation study indicate a very significant under-contribution by streetlights. TOMBEU proposes at this time to apply the same increase to this class as to other customer classes, and to review the costs directly assigned to this class before its next application for adjustments to rates.

For yard lights, a zero rate change would bring this class to a revenue/cost ratio of 95%. Since most of the Utility's anticipated cost increases relate to cost of power, and this class rate includes rental costs as well as electricity use, and the class is small enough that an adjustment will not adversely impact the metered classes, the Utility believes this to be a fair treatment at this time.

8.2 Total Percentage Rate Adjustment

As shown in Exhibit 3, TOMBEU calculates that it would require an increase in rates and charges of 34.8% for the Test Year in order to recover the forecast revenue requirement. Such increase does not include provision for any liability that might result if the Board allows NSPI to recover any further cost increases from customers, including TOMBEU.

In TOMBEU's view, this rate increase is justified by the fact that it reflects TOMBEU's best expectation of actual costs in the Test Year, and that the costs would be incurred despite TOMBEU's diligent efforts to obtain economic supply and to minimize its internal costs to maintain its system and deliver service. As was pointed out in Tab A of this rate study, TOMBEU has not had any increase in its rates, other than supply flow throughs, since 2008.

Nonetheless, TOMBEU is very conscious of the hardship that an increase of this magnitude may impose on its customers, and also anticipates that the Board will share this concern.

Therefore, in parallel with preparation of this proposal for full recovery of its costs in the Test Year, TOMBEU continues to explore mechanisms for rate mitigation, and sources of funding for such mitigation. TOMBEU anticipates being able to report to the Board on the results of this exploration at the time this Application is heard.

8.3 Revenue to Cost Ratios and Proposal as to Class Rate Adjustments

Exhibit 6 shows the calculated revenue to cost ratios, assuming that an equal percentage rate increase is applied to all the metered customer classes and to street lighting. The result is that all metered classes except net metering or very close to the range that has been considered acceptable by the Board. Street lighting appears to be under-recovering, based on this study, and to a degree that might be of concern to the Board.

In performing this cost allocation study, TOMBEU was faced with limitations of data, especially the data necessary to determine class coincident and non-coincident peak responsibility of each customer class. With this consideration, and also in view of the magnitude of the average rate increase that will be necessary to allow TOMBEU to cover costs in the Test Year, and the impact that will therefore be felt by all of TOMBEU's customers, it is recommended that all metered classes be treated equally in terms of rate increases for the Test Year.

As TOMBEU expects to need to file another GRA in the next 18-24 months, a new cost allocation study will be performed at that time, and consideration can then be given to whether differential rate changes are needed and well supported by the data.

8.4 Revenue Reconciliation

The rate increases to each metered customer class are therefore proposed to be equal for the Test Year, and to be recovered through equal percentage increases to each component of the rate structure. This will result, if approved by the Board, in bill increases that are equal among the metered classes, and to the customers individually.

The proposed percentage increase to each customer class is computed in Exhibit 6, which shows the recovery of the revenue shortfall that TOMBEU forecasts if no rate increase is implemented. It is assumed that the increases are implemented to be effective for consumption on and after January 1, 2023, and to be in place throughout 2023.

In presenting rate and charge structures for the Test Year, the Utility proposes to add as a separate charge for all metered customer classes a DSM "rider" of 0.819 cents per kWh to the structure of each rate, which is the same amount that NSPI proposes as a DSM rider in its charges to municipal utility customers. The Utility submits that creating a separate charge for the recovery of this cost will assist customers in comparing the base rates and bills from the Utility with rates in neighbouring service territories. The Utility has computed its other rates and charges in order to equalize the total change in rates, including the DSM rider, to customer classes across all metered classes.

Rates in accordance with these proposals are computed in Exhibit 7, and show that these rates will recover the revenue requirement when applied to the forecast billing determinants.

9 Tab I – Rate Schedules

[to be completed when proposal is agreed for filing]

10 Tab J - Rules and Regulations Governing the Supply of Electric Services

Attached to complete the filing requirements is TOMBEU's Schedule of Rules and Regulations as it currently exists. TOMBEU is considering several amendments to this Schedule, but in the interest of a timely filing of this urgent application for rate relief, TOMBEU is filing without the updates under consideration. TOMBEU will provide these updates at a later date.

BDR

BDR is a leading Canada-based consulting firm specializing in advising on matters related to the electricity and natural gas industries. Our team members have served governments, regulators, consumers, transmission and distribution companies, electricity generators, integrated utilities, and prospective investors in major energy assets.

BDR's key areas of practice are:

- Mergers and Acquisitions
- Business and Strategic Planning
- Regulatory Compliance, Policy and Rates

Our team members bring decades of experience in the energy sector, including leadership within utilities and as consultants. Our team members have project experience in 8 jurisdictions of Canada, as well as in the United States, China, Ghana, Turks & Caicos, and Barbados.

BDR

Our Practice

Overview

<u>Mergers and Acquisitions:</u> A changing industry requires basic reassessments and decisions to merge and/or acquire businesses and to expand some businesses and exit others. BDR staff have managed the process of merger, divestment and acquisition of both generation, “wires”, and utility affiliate business, such as water heating, construction and telco. Key in these assignments is the development of a valuation for the enterprise.

<u>Business and Strategic Planning:</u> BDR staff has completed strategic business plans and options analyses for well over 100 clients in the electricity sector. These plans include consideration of the strengths and weaknesses of the client in a range of business options, all of which are assessed in the context of the current technological, economic, government and regulatory climate of the business.

<u>Regulatory:</u> BDR advises clients who are regulated entities in all aspects of dealing with regulators. This includes supporting applications for mergers and acquisitions, studies in support of rates and revenue requirements, such as cost of capital, cost allocation and working capital analysis. Services include analysis and expert testimony where required.

BDR

Our Practice

Mergers and Acquisitions

In an active, rapidly changing North American energy sector, clients have turned to this team for nearly two decades to support new investment, merger, acquisition and divestiture decisions with:

- due diligence investigation and fairness opinion
- financial modeling and valuation
- sector/jurisdictional environmental scan and industry overview
- regulatory insights
- assessment of acquisition candidates or potential merger partners
- analysis of bidding strategies
- support in the negotiation process.

Assets involved include distribution and transmission ("wires") a variety of generation plants, and related businesses such as telecommunications and rental appliances. We have also advised proponents in RFP processes for new electricity supply.

BDR

Our Practice

Business and Strategic Planning

Clients have turned to this team to assist in a variety of strategic and business planning decisions. In the initial stages of industry restructuring in Ontario, over 100 distribution utilities consulted us in matters of ownership and financing options, business structure and business portfolio alternatives. Since that time, we continue to advise clients considering a variety of new energy sector business projects, developing strategic plans or offering assets for sale.

Our business and strategic planning services include project cash flow analysis, strategic planning meeting facilitation, assessment of qualitative and stakeholder issues, and financing advice.

BDR

Our Practice

Regulatory and Rate Design Services

Building on years of experience in positions within regulated electricity and natural gas utilities, BDR consultants offer clients a core competency in matters related to economic regulation and approval of rates. Our services include:

- rate designs, including bundled and unbundled pricing
- background studies in support of rate designs, including load research and cost allocation
- development of revenue requirement
- special studies in support of revenue requirement, including cost of capital, working capital (lead lag), and allocation of joint costs among affiliate business units
- development of applications for approval of facilities (both approval to construct and approval for cost recovery in regulated rates)
- intervention advice to consumers
- analysis and expert testimony.

We have also advised regulators and government in matters of policy.

BDR

The BDR Team

BDR brings together a small core team of senior energy utility and investment banking professionals. Our senior staff are hands-on in every assignment, for every client, large or small. Our core competencies are mergers/acquisitions, business planning, project financial analysis, regulatory policy, cost allocations and rate design. Our qualifications include MBA degrees, accounting designations and civil engineering.

The BDR team also maintains a network of allies with complementary skills and experience. When these skills are needed, we bring our clients an integrated project team that may include electrical engineers, lawyers, economists, forecasters statisticians, public practice accountants or specialists in metering, IT and communications. The BDR core team members are disciplined project managers, offering the right skill sets from the right providers, seamlessly.

Our firm's principals are:

John McNeil – President

John is a lawyer by training and an independent investment banker by profession. He has over 30 years experience in the areas of business and enterprise valuations, financing and capital markets activities, and mergers and acquisitions (M&A). He has worked extensively throughout North America and in the United Kingdom and over the past twenty years he has specialized in the energy sector.

In his consulting practice, John has advised Ontario municipalities and utility clients considering mergers, acquisitions and divestitures, joint ventures, and the formation of service affiliates. In addition to his expertise in the business and operational issues associated with combining operations, John has expertise concerning the regulatory issues that arise from mergers and business combinations. John recently led the team in a due diligence and advisory assignment for the PowerStream shareholders which led to the formation of Alectra Inc.

Paula Zarnett, Vice President

An energy sector professional with 30 years' experience, Paula fulfilled progressive responsibilities in natural gas and electric utilities leading to a position as manager of marketing at Toronto Hydro. Within Toronto Hydro, she coordinated the utility's first strategic planning process, spearheaded a two-year program of corporate performance improvement including benchmarking and process re-engineering, and was a member of the team to address the re-organization issues associated with amalgamation of the six former metropolitan Toronto electric utilities. She also participated in development of a framework to evaluate new business opportunities.

In her consulting practice, Paula has advised Ontario municipalities and utility clients considering mergers, acquisitions and divestitures, joint ventures, and the formation of service affiliates. In addition to her expertise in the business and operational issues associated with combining operations, Paula is knowledgeable in regulatory issues affecting the value of distribution businesses, and has presented expert testimony to regulators in several Canadian jurisdictions.

Paula has successfully managed numerous concurrent projects, and is a skilled facilitator of cross-functional project teams. She is also a skilled modeler, with expertise in the use computer-based analytical tools.

Paula holds a CPA,CMA designation and an MBA degree in Finance from the University of Calgary.

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Why hire BDR?

- ✓ Senior staff have hands-on involvement in every assignment
- ✓ Years of direct experience in leadership positions within utilities
- ✓ In-depth knowledge of financial markets, investment banking, merger and acquisition transactions
- ✓ Ability to “team” with skilled, experienced industry allies to provide additional specialized expertise
- ✓ Long personal involvement in the electricity sector and extensive gas experience
- ✓ No “packaged” solutions – each assignment carried out to meet the client’s specific needs and situation

BDR

Contact Us

BDR operates as a virtual company. Our principals are resident in Toronto, Canada.

Please contact us by telephone or email.

John McNeil: jmcneil@bdrEnergy.com
416-540-2230

Paula Zarnett: pzarnett@bdrEnergy.com
416-807-3332