Very Small Utilities Working Group Report

EB-2023-0229

Prepared By: Very Small Utilities Working Group

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1 INTRODUCTION

In November 2022, the Ontario Auditor General's (AG) office released its Report on the Value-for-Money audit titled, *Ontario Energy Board: Electricity Oversight and Consumer Protection*. One of the items identified by the audit related to the regulatory burden on very small utilities or local distribution companies (LDC's) – LDC's with less than 5,000 customers - in filing major rate applications. To help reduce that regulatory burden, the AG recommended that the OEB evaluate the impact of its relevant regulatory efficiency initiatives on very small utilities and identify areas for improvement within an established timeline. In addition, the report recommended the OEB develop procedures to continuously monitor the impact of relevant regulatory initiatives on very small utilities and implement further actions as warranted.

As a result, a Working Group was formed consisting of representatives from eight very small utilities across Ontario including the Electricity Distributors Association (EDA); Cornerstone Hydro Electric Concepts (CHEC); Tandem Energy Services Inc.; one intervenor Vulnerable Energy Consumers Coalition (VECC)); and OEB staff. The participating very small utilities include:

- Atikokan Hydro Inc.
- Cooperative Hydro Embrun Inc.
- Fort Frances Power Corp.
- Hearst Power Distribution Company Limited
- Hydro 2000 Inc.
- Renfrew Hydro Inc.
- Sioux Lookout Hydro Inc.
- Wellington North Power Inc.

The Working Group met eight times between September 2023 and January 2024 to identify and find solutions to the challenges faced by very small utilities in complying with the OEB's regulatory framework, especially in the preparation of Cost of Service applications. This report describes those challenges and potential solutions proposed to the OEB.

The Working Group has not proposed a final solution to every issue identified, but believes in time, further initiatives could be developed in those areas.

The scope for the Working Group was initially focused on, but not limited to, the following[1]:

- The Cost of Service application process
- Current OEB regulatory efficiency initiatives (Updates to the OEB's *Filing Requirements for Electricity Distribution Rate Applications* (Filing Requirements) as they relate to smaller LDCs and review of intervenor processes and cost awards), with attention to impact on very small utilities
- The major components of Cost of Service rate applications (as set out in the Filing Requirements)
- A process to regularly monitor and review impact of regulatory initiatives on very small utilities

The Cost of Service application process

The Working Group identified that many steps in the Cost of Service process, while required, can be burdensome for very small utilities. Most small utility applications are settled prior to an OEB hearing. Therefore this report focuses on how to reduce the burden related to the interrogatory and settlement conference processes. To reduce the burden, the Working Group is proposing adding a meeting day prior to the filing of interrogatories and so as to provide the opportunity to parties to more informally discuss the issues, questions about the application and the need for interrogatories prior to the interrogatory and settlement dates. The intended purpose of this new process day is to reduce the scope and number of interrogatories. To reduce the application's financial burden on very small utilities the Working Group is also proposing that a member of OEB Staff be substituted for an external facilitator for the settlement conference.

Current OEB regulatory efficiency initiatives and major components of Cost of Service rate applications

The Working Group members identified that while intervenor cost is one component of regulatory costs for major rate applications, there are other application-related costs that are more significant. In addition to intervenor costs, very small utilities with limited staff resources incur significant costs for hiring expertise to develop a distribution system plan, an asset management report, write and check evidence filed in accordance with

[1] https://engagewithus.oeb.ca/regulatory-efficiency-for-small-utilities?tool=news_feed

the OEB's filing requirements, legal costs for representation at OEB events and the OEB's own costs (like settlement facilitation).

- In considering the cost challenges of a Cost of Service rate application, and ultimately for determining the proposed rates.
- The need to hold formal customer engagement as part of the application process.
- The need to hire legal expertise to navigate the application process.
- Intervenor costs.

This Report focuses on the challenges of making it more cost efficient for very small utilities filing a Cost of Service application. Generally, what the Working Group found is that there is the need (or perceived need) for utilities to acquire expensive outside technical assistance in support of their filings. These outside costs increase the cost of a COS application. For example, the OEB's Filing Requirements do not explicitly require a third party to "validate" a filed DSP or to review an asset management process. However, as a practical matter many utilities, including the smallest, perceive the need to seek outside assistance to support their cases. They do so because they can expect to be queried by intervening parties and OEB Staff on the robustness of their plans and for the OEB to apply the burden of proof to the Applicant.

The Working Group has included a sample DSP and Normalized Average Use per Customer (NAC) load forecast methodology to assist very small utilities in meeting filing requirements with in-house resources and reinforce that fulfilling the filing requirements does not always require third party assistance. Without the need to retain a third-party, it is anticipated that very small utilities Cost of Service application costs will be reduced.

<u>Intervenor Costs</u>

The AG's Report focused on intervenor costs as a component of regulatory burden. In its Report, the AG notes that "[T]*he costs associated with the Board's rate making process may outweigh certain benefits when it comes to very small LDCs (that is, those LDCs with fewer than 5,000 customers*." For very small utilities the AG found that while there was a net benefit found in the cost reductions resulting from the advocacy of intervenors, the savings were proportionally less than for larger utilities.

VECC, who is the primary intervenor in very small utilities Working Group noted to the Working Group that while it made particular effort to minimize its costs for very small utilities, the Cost of Service filing requirements, in whatever form they take, including those suggested in this report, require a minimum amount of effort to read, assimilate and make cogent submissions on. Unless the OEB were to reconsider the methodology as to how or how often to set Cost of Service rates for these utilities, there is little room to reduce intervenor costs further other than by limiting the number of intervenors or the time they may spend analyzing an application. As such the Working Group recommends that the OEB consider alternative methods of setting and adjusting rates for the smallest of utilities with an objective of providing reasonable rates at a reasonable cost of rate regulation.

In considering alternative forms of regulation the OEB might wish to consider that very small utilities inherently have less complex issues with respect to the cost of service. Very small number of staff and limited capital budgets leave relatively little room to maneuver. Conversely, small utilities can struggle with the requirements of sophisticated accounting and regulatory and government policies which are premised (purposely or not) on internal or affordable external expertise. For large utilities the costs of providing distribution service is the most pervasive issue and the inherent technical capability of management and governance is of little concern. For very small utilities the opposite can be true. This might argue for a different form of rate regulation and on in which rate comparability and a focus on ongoing audits and monitoring are more appropriate.

A process to regularly monitor and review impact of regulatory initiatives on very small utilities.

In the spirit of continuous improvement, the Working Group has considered establishing regular touchpoints in the future where the effectiveness of changes identified in the Working Group Report may be reviewed and revisions to the OEB's process and filing requirements could be further considered. These meetings may also include a debrief of any very small utility Cost of Service proceedings that have concluded since the previous Working Group meeting.

OEB staff will also track regulatory costs including application preparation costs and intervenor costs for further discussion with the Working Group.

2 FILING REQUIREMENTS

2.1 Issues

The Working Group believes that the existing Chapter 2 Filing Requirements (Chapter 2 pertains to Cost of Service applications) are onerous for very small utilities in that they establish the expectation for advanced forecasting techniques (be they load forecasting or detailed asset condition assessments) that may not be necessary for utilities with very small customer bases and predictable capital programs.

2.2 Potential Avoided Costs

By rationalizing or reducing the Chapter 2 Filing Requirements for very small utilities, these utilities would primarily avoid internal utility costs (i.e., overtime, additional staff, and miscellaneous costs). Very small utilities could potentially also avoid consultant costs since many of these utilities hire consultants to provide project management, help write their evidence and develop the models that support that evidence.

2.3 Working Group Proposal

The Chapter 2 Filing Requirements have been reviewed twice in the past three years. The intention of the Working Group was not to revisit the Filing Requirements exhaustively but to instead focus on the requirements that place the greatest burden on very small utilities, as identified by those utilities participating in the Working Group. Given that the Working Group did not revisit the Chapter 2 Filing Requirements in thorough detail, it is essential that the Working Group identifies what the OEB and intervenors really need to effectively evaluate an application given the onus on very small utilities to explain and provide information to support their requests.

The Working Group believes there are opportunities to reduce the amount of discussion required in an application by improving on the existing Excel models and by reducing duplicate information required between Exhibits or within the same Exhibit (for example: information required in the Distribution System Plan and Exhibit 2). There could also be improvements to the instructions in the models.

3 DISTRIBUTION SYSTEM PLAN

3.1 Issues

Chapter 5 Filing Requirements (which deals with Distribution System Plans) has continually been refined with the intent to provide a better understanding of an LDC's distribution system, asset management strategy, decision-making process for capital investment and historic performance of execution of a 5-year plan. With the growing desire for more information and complexity of data required as utilities continue to manage the energy transition, very small utilities feel the pressure of increased requirements, and many have opted to outsource the preparation and writing of the DSP to third-party consultants. Furthermore, some LDCs that have written their own DSPs have retained third-party consultants to validate the completeness of the DSP and its alignment to the Chapter 5 Filing Requirements.

In addition, and in accordance with good utility practice, the Chapter 5 Filing Requirements state that in assessing the condition of major assets (i.e., poles, transformers, etc.), solely using asset age is not sufficient. This has prompted some LDC's to feel the need to hire a third-party consultant to prepare a formal Asset Condition Assessment. The Working Group has identified that third-party costs related to the DSP make up a significant portion of overall application costs.

3.2 Potential Avoided Costs

By removing the perceived expectation for certain advanced assessments and preparation of data to assess the state of a utility system, third-party costs that could be avoided include:

a) Prepare/review of LDC written DSP to ensure it meets and aligns with the Chapter 5 Filing Requirements

b) Preparation of a formal Asset Condition Assessment

For those LDCs that have written and filed their own DSP, meeting the current Chapter 5 Filing Requirements has resulted in extensive labour hours. If the Chapter 5 Filing Requirements were "simplified", this would result in less in-house labour needed to prepare a DSP in-house.

By having a "simplified" DSP for very small utilities whereby the DSP filing requirements compliment the size of the utility (i.e., number of assets and amount of capital expenditure to maintain assets), it is more likely that very small utilities will write their own DSPs rather than outsource to a third-party consultant.

3.3 Working Group Proposal

In forming a “simplified” DSP, the Working Group has developed a DSP sample, as attached in Appendix A. The Working Group believes the DSP sample attached can be undertaken by all very small utilities in-house and is sufficient for the OEB in evaluating the utility’s system planning, asset management strategy and capital expenditures that support the potential reasonableness of the in-service additions for the Test Year.

4 LOAD FORECAST

4.1 Issues

As part of a Cost of Service application, LDC's are expected to provide an updated load forecast. The Filing Requirements note two typical types of load forecasting models used in Cost of Service applications: Multivariate Regression and NAC.[2] Very small utilities feel that load forecasts can be constructed based on the LDC's historical growth, future projections, and customer mix. However, they feel that there is an expectation that the multivariate regression method be used in most cases.

The technical knowledge, resources, or time required to compose a load forecast using a multi-variable regression analysis may not provide adequate net benefits when compared to outcomes from the use of simpler and less costly approaches. Multivariate regression is a technical / mathematical approach that requires knowledge, experience, resources and can be time-consuming, very small utilities feel the need to consult third-parties in order to employ more complicated methods, which increases the overall application cost.

4.2 Potential Avoided Costs

A simpler load forecast that can be done by LDC staff would avoid both internal labour hours and third-party costs for very small utilities during both the development of the load forecast and during the interrogatory process of a Cost of Service application.

4.3 Working Group Proposal

The Working Group recommends that the OEB further clarify that a simpler approach can be acceptable and also recommends that the OEB provide a model that can be used by utilities to develop their load forecasts in-house.

The Working Group has included a proposal for a sample load forecast model using a NAC approach (Appendix B). The Working Group believes very small utilities could replicate such a model without third-party assistance. The Working Group is aware that the NAC model is useful for simple scenarios and could generate more complex interrogatories if it is used for more complex scenarios. However, the Working Group believes that the OEB can revisit how the approach is working in the future.

[2] Chapter 2 Filing Requirements, December 15, 2022, pp. 25-27

5 LOAD PROFILES

5.1 Issues

The load profiles currently being used by many very small utilities within a Cost of Service application are the 2006 versions that were developed by Hydro One. These load profiles are being used given that it is a large undertaking to develop a new set and very small utilities do not have the resources or time.

Additionally, while the very small utilities recognize that the demand profile data for multiple years may be necessary to ‘normalize’ the demand (i.e., reduce or eliminate COVID-19 data), they also feel that that collecting and analyzing hourly data at a per-meter level is extremely time-consuming (8,760 hours of data in 1 non-leap year). As a result, such a task could result in very small utilities retaining third-party assistance to prepare the rate-class demand profile, thereby increasing costs for the application.

5.2 Potential Avoided Costs

Solving the need to develop complex load profiles would reduce the costs associated with both third-party consultations and internal labour hours for very small utilities.

5.3 Working Group Proposal

The Working Group is not proposing a solution to this issue at this time. However, the Working Group would be open to exploring possible solutions with the OEB at a later date, including but not limited to:

- For a very small utility’s next application, if there had been minimal change in load growth and customer numbers / customer-mix, the Working Group suggests that the OEB allow the very small utility to use the same demand profile allocators as previously filed. This is assuming a very small utility had previously prepared, submitted and had approved its demand profile using recent data in an application.

- Allow very small utilities to use a single year of Demand Profile data (COVID-19 free) for its demand profile allocators in the Cost Allocation Model. The Working Group does recognize that using such an approach may cause concerns if the revenue to cost ratios are not close to 100%.

- The OEB hire a consultant to develop a new set of load profiles for use by the industry.

- Have the IESO create load profiles for residential and GS<50kW rate classes through the Meter Data Management/Repository.

6 OEB MODELS

6.1 Issues

The Working Group believes that the manner in which the existing Cost of Service models have evolved (most notably the automation that has been built in over the years) has made the models more complex and has raised challenges for some utilities in terms of populating and running them. For utilities that do not use them often or do not have the expertise, especially when the models malfunction in some utility specific circumstances, assistance from OEB staff has been required to address and correct issues.

In addition, annual updates to the models are issued late for those LDCs looking to file for January 1 rate adjustments. Due to the models being issued later than needed, utilities are forced to do major re-work and/or need to develop work arounds to force the models to work. Overall, the issuance of updated versions of models is inefficient since utilities need to transfer information to new models.

Another issue identified by the Working Group involves the Bill Impact model. The model includes pass-through costs (for example, retail transmission service rates, smart meter entity charges, regulatory charges) that are outside of the control of the LDCs. Very small utilities believe that such models should only highlight rates controlled by the LDC, including the service charge, distribution volumetric rate, and revenue requirement for regulatory dispositions/recovery.

6.2 Potential Avoided Costs

By simplifying the Cost of Service models, very small utilities may not need to hire external consultants to manage the modelling associated with a rate application.

6.3 Working Group Proposal

The Working Group suggests that the OEB explore the development of a set of simplified models for very small utilities. The Working Group further suggests that either the OEB hire a consultant or that additional Working Group resources can be used to undertake such a task.

The OEB could also offer training on the models for very small utilities to reduce the potential need to hire external consultants to manage the models in a rate application.

7 EXISTING COST OF SERVICE PROCESS

7.1 Issues

The Working Group is of the view that the existing Cost of Service process steps are logical and needed. However, many of the steps, including the discovery and settlement conference process take a long time to complete, and the volume of documentation can be burdensome for very small utilities. In addition, the Working Group believes that the steps of the process would be expedited if the application were smaller for very small utilities as long as the OEB has the information it needs to make an informed decision. The Working Group accepts, though, that any process changes need to still ensure that the process remains transparent and open.

A major pain point identified in the current process is interrogatory responses. Very small utilities find that there are too many interrogatories filed between intervenors and OEB staff. Responding to interrogatories takes many internal resources in a short period of time. Very small utilities also believe that certain hypothetical, unrealistic interrogatories or interrogatories that seek many different scenarios and that add little to no value in comparison to the amount of work required to respond to them, should be avoided.

A third-party facilitator for settlement conferences also drives costs for the application process. The Working Group believes that OEB staff not involved in the application could facilitate the settlement conference to reduce facilitation costs.

7.2 Potential Avoided Costs

By reducing the expectation in the number of interrogatories, very small utilities would avoid internal labour hours, as well as any need for third-party assistance in responding to interrogatories. While intervenor costs for proceedings reviewing applications from very small utilities are not significantly high, this initiative would also potentially reduce intervenor costs further.

7.3 Working Group Proposal

The Working Group proposes an update to the Cost of Service process for very small utilities as found in Appendix C. The update includes a 1-day meeting, in which parties discuss the application to distill issues for discovery. The goal of the meeting is to a) reduce the number of interrogatories filed; and b) decide if interrogatories can be forgone, thereby allowing parties to proceed directly to the settlement conference process. To offset the 1-day meeting, the Working Group is proposing to reduce the settlement conference period to 2 days, thereby offsetting intervenor and internal labour costs for the utility for the 1-day meeting.

The Working Group also proposes to use OEB staff as a facilitator for the settlement conference.

8 MATERIALITY THRESHOLD

8.1 Issues

According to the Chapter 2 Filing Requirements, the materiality threshold for providing variance analyses is $10k for LDCs with fewer than 30,000 customers and a base revenue requirement less than or equal to $10 million. For a revenue requirement greater than $10 million the materiality threshold is 0.5% of base revenue requirement. For capital expenditures, this applies at the capital expenditure or in-service addition amount levels and not at the revenue requirement level. Despite the fact that there is no requirement for a year over year variance analysis, and that utilities doing an analysis of historical OEB approved to test year spending, for example, would multiply this number by 5 times (making it a $50k threshold), very small utilities feel that the $10k materiality threshold is still too low. A $10k materiality threshold results in a great deal of additional work compared to the previous materiality threshold of $50k. The current threshold exceeds the purchase of (for example) a single three-phase padmount transformer or computer server, leading to the need for explanations for numerous projects and programs.

The Working Group acknowledges that the previous $50k threshold was applied on a revenue requirement basis which may have been much too high for very small utilities. Setting a materiality threshold too high causes another potential problem where many very small utilities expenditures fall under the materiality threshold and the very small utility is in theory not required to fully tell their story to justify their costs. While many utilities have in the past voluntarily provided more information in their pre-filed evidence than would have been required by abiding by the materiality threshold, a threshold that is too high may prevent intervenors or OEB staff from sufficiently testing certain information.

8.2 Potential Avoided Costs

By increasing the materiality threshold for very small utilities, the very small utilities may see a decrease in application size, thereby reducing labour hours internally and/or for third-party consultants.

8.3 Working Group Proposal

The Working Group believes that possible solutions could include restoring the materiality threshold to $50k or basing the threshold on a percentage of the revenue requirement or a percentage of the capital budget. The Working Group can revisit the materiality threshold with OEB staff prior to the next revision of the filing requirements.

9 CUSTOMER ENGAGEMENT

9.1 Issues

Although the Chapter 2 Filing Requirements do not require customer engagement surveys for their cost of service application, very small utilities feel that there is an expectation for them to conduct surveys. Very small utilities have identified these surveys as expensive relative to the benefits of capital planning given their overall size and capital investment needs. Very small utilities find that customer engagement surveys provide little value to the development of the DSP given that their expenditures are largely routine. Very small utilities have also found surveys from LDCs of all sizes have shown that customers want reliability and reasonable pricing.

Additionally, many very small utilities have noted that their offices are open to their customers and the public to provide feedback.

9.2 Potential Avoided Costs

By removing the expectation of customer engagement surveys, very small utilities would avoid the need to retain third-party marketing firms, thereby reducing regulatory costs of the application. Eliminating the expectation of surveys would also save very small utilities labour hours in preparing and managing the surveys that may have little or no impact on the DSP or outcome of the application.

9.3 Working Group Proposal

The Working Group is recommending that the OEB clarify that other methods of obtaining customer feedback would be acceptable, including some combination of the following options:

- Having each very small utility conduct a 1-day Town Hall in which customers can voice their concerns and provide a summary to the OEB. If no customers participate, the LDC could then explain this in its application.
- Provide a plain language summary of the application to customers through bill inserts, newspapers, and email and ask for feedback. The feedback and how the very small utility addresses it will be documented.
- Developing a simplified customer survey that can be used by all very small utilities on a regular basis to obtain customer feedback. It should be noted that customer surveys are just one of many methods very small utilities use to obtain

customer feedback. These LDCs also use (among other methods) their websites, bill inserts, meetings with business associations, developers and local fairs.

- A standardized Public Awareness of Electrical Safety questionnaire was developed for use by all LDCs to assess the level of electrical safety awareness of the general public. The Working Group recommends that a similar set of core questions be developed for use during biannual Customer Satisfaction surveys that satisfy both Customer Satisfaction and Customer Engagement requirements (associated with filing a Cost of Service application).
- Using OEB complaints and letters of comment raised against the very small utility as a barometer of if there any underlying concerns that the utility is failing to meet.

10 PAYMENT IN LIEU OF TAXES

10.1 Issues

The small business tax deduction is applicable when taxable capital is less than $50 million. For actual tax purposes, some very small utilities do not qualify for the small business tax deduction because their total taxable capital including their affiliates' taxable capital is over $50 million. However, for regulatory purposes, the stand-alone principle only considers if a very small utility's taxable capital qualifies for the small business tax deduction. A discrepancy between the regulatory treatment and the actual tax treatment exists when a very small utility qualifies for the small business tax deduction for its actual PILs filings but does not qualify for such deduction in its rebasing application. Such discrepancy is permanent for the Very Small Utility if the OEB applies the stand-alone principle in its regard strictly in the rebasing applications.

10.2 Potential Avoided Costs

By addressing the discrepancy between actual and regulatory tax calculations, the PILs expense will be set in line with a very small utility's actual tax experience.

10.3 Working Group Proposal

The OEB is in the process of addressing the identified issue. Any change that the OEB may determine is appropriate may become part of the next version of the filing requirements.

11 VERY SMALL UTILITY REGULATORY PROCESS

11.1 Issues

The Cost of Service process by its very nature challenges the utility to demonstrate that its plans are robust. Large utilities achieve this objective by hiring outside consultants to "validate" their applications. Consulting costs are directed primarily to the DSP, Asset Management Plan, Customer Engagement supporting a DSP and the technically competent load forecast needed for the application.

The fact is that very small utilities have very small asset bases and it is questionable whether the plans for the smallest utilities should be, or need to be the same as the intricate and robust plans supplied by large utilities. Arguably the primary regulatory concern with the smallest utilities is not costs. Very small utilities have a small number of employees and very limited cost objectives. It is very difficult to create efficiencies when the base costs are so small. The regulatory focus might be more efficiently placed on the robustness of small utility governance, management and technical competence. The challenges for very small utilities are operating with very limited resources and often in isolated locations. This argues for a different form of rate regulation for these utilities - one that is less focused on costs and more critical of management and management practice as validated through a series of audits on the ongoing functionality of the utility.

The Working Group also believes that the current regulatory process framework of filing a Cost of Service application every 5-8 years does not scale for very small utilities given the number of customers and the LDC's need. Therefore, the Working Group believes there are opportunities to regulate very small utilities using differing approaches.

11.2 Potential Avoided Costs

By removing the need for a Cost of Service process every 5-8 years for very small utilities, ratepayers would see a decrease in regulatory costs associated with intervenors, legal fees, third-party consultation, and internal labour hours.

11.3 Working Group Proposal

Although the Working Group is not currently proposing a change to the framework, it does believe alternatives can be explored in the future to indefinitely extend the number of years a very small utility could remain on Price Cap IR. Alternatives suggested include:

- Using a metric approach to regulate very small utilities (i.e., using the OEB scorecard or other metrics captured through the OEB's Reporting and Record Keeping Requirements) to determine when a very small utility should next rebase.

- Periodic visits to the very small utility's service territory to ensure that the utilities that have not rebased over a long period are operating its system in a safe and reliable manner and replacing assets as necessary / identified in its asset management plans.

- Have a very small utility include a target level of asset health it is seeking to maintain within its asset management plan filed with a Cost of Service application. These targets could then be used annually to demonstrate that assets are being managed appropriately.

- Consider focusing on the robustness of very small utility governance, management, and technical competence.

APPENDIX A

VERY SMALL UTILITIES WORKING GROUP REPORT

EB-2023-0229

FEBRUARY 28, 2024

Introduction

- All utilities are expected to meet the Chapter 5 Filing Requirements with respect to their Distribution System Plan (DSP).
- Very Small Utilities (VSU) should describe the processes and practices they utilize to make decisions on their assets.
- Outlined below are some examples of the type of information that could be provided to inform OEB staff / intervenors how VSU's make decisions and to help fulfil the Chapter 5 filing requirements.
- An example of a VSU DSP that utilizes this approach is attached with references to it below.

Purpose of the VSU DSP example

1. To provide a guide for Very Small Utilities (<5,000 customers) in developing their Distribution System Plan.
2. The capability for the Distribution System Plan for Very Small Utilities (DSP for VSU) to be prepared by the utility and not a 3rd party.
3. The ability for a VSU to prepare its DSP in a timely and cost-effective manner.
4. A guide for VSU to prepare a DSP to meet the Chapter 5 Filing Requirements and the expectations of Intervenors and OEB Staff.
5. To focus on exceptional items, i.e., what is the problem, why, what is the solution and why is that the best solution.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
5.0 Introduction These Chapter 5 filing requirements set out the relevant information required by the Ontario Energy Board (OEB) in accordance with the renewed regulatory framework (RRF) for electricity and the Handbook for Utility Rate Applications (Handbook) to assess distributor applications involving planned expenditures on distribution systems and general plant. A Distribution System Plan (DSP) consolidates the documentation related to a distributor's asset management process and capital expenditure plan, as described in the Handbook. Good distributor planning is an essential prerequisite to the performance-based rate-setting approaches established under the Handbook, and necessary to ensure that the four performance outcomes the OEB has established for electricity distributors, namely Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance, are being achieved.	A VSU would need to include a statement that its DSPs contributes to the utility's achievement of the 4 performance outcomes as noted by the OEB in the RRF The VSU DSP Sample has an Asset Management Process and Capital Expenditure Plan. (e.g., Section 3. Planning Process, Section 4. Capital Expenditure Plan) A VSU should be able to demonstrate good distributor planning by explaining how they take data, evaluate it through their planning process, and the development of capital expenditure plans as a result of their planning process evaluation. A VSU could provide a table to show how they're planning process meets the four performance outcomes. (e.g., Section 1.3 Asset Management Objectives)
5.0.1 Application and Scope These filing requirements apply to licensed, rate regulated electricity distribution utilities in Ontario when filing DSPs in accordance with the frequency set out by the OEB in section 5.1.3 of these requirements.	The VSU will meet the chapter 5 filing requirements.
5.0.2 The OEB's Evaluation of DSPs DSP filings must address whether a distributor has achieved and will continue to achieve the four performance outcomes the OEB has established for electricity distributors. Section 5.4.2 explains the specific criteria the OEB will use to evaluate whether a DSP, and in particular the material projects/programs proposed for cost recovery in a DSP, addresses these four outcomes.	
5.1 General & Administrative Matters	

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
These filing requirements provide a standardized approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application. Distributors are expected to include and clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.	
5.1.1 Purpose of Filing a Distribution System Plan To implement the policy objectives of the RRF as set out in the Handbook, all filing requirements related to DSPs have been consolidated in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications. Filing a DSP with an application to the OEB will provide information to the OEB and interested stakeholders including, but not necessarily limited to, a distributor's approach to evaluating its performance, management of its assets, and capital investment plans.	The VSU DSP should be able to explain the objectives of the capital expenditure plan, explain how the VSU arrived at the capital expenditure needs, and provide the data the VSU relies on to assess and develop its capital expenditure plan.
5.1.2 Investment Categories • ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system that a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system. • ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. • ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.	The VSU will use the four investment categories as set out in Section 5.1.2

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
• ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities.	
5.1.3 Timing of Filing All distributors are required to file a DSP when filing a cost of service application under a Price Cap Incentive Rate-setting (IR) or a Custom IR application (collectively referred to as rebasing applications). Distributors proposing to use the Annual IR Index method are not required to file a DSP when filing an application.6 The OEB may also require a DSP to be filed in relation to an Incremental Capital Module, a Z-factor application, or following a merger / acquisition / amalgamation / divestiture application	A VSU need only file a DSP upon a Cost of Service re-basing application, or as directed by the OEB.
5.2 Distribution System Plans Distributors are encouraged to organize the required information using the section and subsection headings indicated from here onwards. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall provide a table that clearly cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in these filing requirements. Distributors are also encouraged to structure the application so that all DSP appendices and supporting materials are included after the main DSP body text, to facilitate review. The DSP's duration is a minimum of ten years in total, comprising an historical period and a forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of the distributor's last cost of service application to	The VSU will provide at least 5 years historical data and 5 years of forecast data. If a VSU DSPs has its own headings a table should be provided to show how the VSU believes it has met the Chapter 5 filing requirements.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application.	
5.2.1 Distribution System Plan Overview The distributor must provide a high-level overview of the information filed in the DSP and is encouraged not to unnecessarily repeat details contained in the rest of the DSP. The overview should include capital investment highlights and changes since the last DSP. A distributor should list the objectives it plans to achieve through this DSP, which will be used as a baseline comparison in the performance measurement section below. This DSP will be used to inform and potentially support any requests for incremental capital module (ICM) funding during the 5-year DSP forecast period.	The VSU will provide a high-level overview of the information filed in the DSP. In particular, the VSU should describe any issues that are being address over the test year and forecast years, if any. A VSU DSP can provide the objectives it plans to achieve and change since the last DSP through a table. (e.g., Section 1.3. Asset Management Objectives)
5.2.2 Coordinated Planning with Third Parties A distributor must demonstrate that it has coordinated infrastructure planning with customers (e.g., large customers, subdivision developers, and municipalities), the transmitter (e.g., Regional Infrastructure Planning), other distributors, the Independent Electricity System Operator (IESO) (e.g., Integrated Regional Resource Planning) or other third parties where appropriate. A distributor should explain whether the consultation(s) affected the distributor's DSP as filed and, if so, provide a brief explanation as to how. For consultations that affect the DSP, a distributor should provide an overview of the consultation and relevant material supporting the effects the consultation had on the DSP. An overview of any consultation(s) should include: The purpose and outcome of the consultation; whether the distributor initiated the consultation or was invited to participate in it; and the other participants in the consultation process (e.g., customers, transmitter, IESO).	The VSU will provide a summary of its 3rd party coordination. Demonstration that a VSU has coordinated with third parties could include items such as meetings/discussions with third parties and providing the outcomes of those meetings/discussions.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
A distributor should file the most recent regional plan (Integrated Regional Resource Plan, Regional Infrastructure Plan). In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter. Further, a distributor is required to identify any inconsistencies between its DSP and any current Regional Plan. If there are any inconsistencies, the distributor shall explain the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan. *<u>Telecommunications Entities</u>* On January 11, 2022, the OEB issued further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan • The number of consultations that were conducted and a summary of the manner in which the distributor determined with whom to consult. • A summary of the results of the consultations. • A statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how. *Renewable Energy Generation (REG)* A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region. If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP.	

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
5.2.3 Performance Measurement for Continuous Improvement *Distribution System Plan* Distributors are expected to summarize objectives for continuous improvement (e.g., reliability improvement, number of replaced assets, and other desired outcomes) the distributor set out to address in its last DSP and to discuss whether these objectives have been achieved or not. For objectives not achieved, a distributor should explain how it affects this DSP and, if applicable, improvements a distributor has implemented to achieve the objectives set out in this DSP Section 5.2.1. *Service Quality and Reliability* Chapter 7 of the OEB's *Distribution System Code* outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. A distributor is required to provide the reported SQRs for the last five historical years. A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any under-performance should also be explained. A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. A distributor must confirm that data is consistent with the scorecard or must explain any inconsistencies. A summary of performance for the historical period using the methods and measures (metrics/targets) identified and described above, and how this performance has trended over the period.	The VSU will provide an overview of the metrics it uses to measure the effectiveness of its distribution system plans These could include: - Planned/actual assets replaced - OM&A per Customer - Power quality measures - Service quality and Reliability metrics - Interruption information - Other metrics as developed and used by the VSU A VSU DSP could summarize the objectives it planned to achieve in a DSP through a table which should include a quantitative summary of what it planned to achieve, if applicable. For reliability, a VSU DSP could provide tables or graphs for the SAIDI and SAIFI numbers (all interruptions, excluding Loss of Supply (LOS), excluding Major Event and LOS). It should also provide 3 tables by cause codes (# of interruptions, # of customers interrupted, and # of customer hours interrupted) (e.g., Section 3.2.1.1 Cause Codes for Power Interruptions).

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
5.3 Asset Management Process A distributor must use an asset management process to plan, prioritize, and optimize expenditures. The purpose of the information requirements set out in this section is to provide the OEB and stakeholders with an understanding of the distributor's asset management process, and the links between the process and the expenditure decisions that comprise the distributor's capital investment plan.	The VSU is to describe its asset management process to plan, prioritize and optimize expenditures. The VSU should also identify the data it relies on. These can include: • Inspection results and condition. • Asset capacity utilization/constraint assessment • Historical period data on customer interruptions caused by equipment failure • Reliability-based 'worst performing feeder' information and analysis • Reliability risk/consequence of failure analyses What is key is that the VSU describes the process it uses. This section is customizable to suit each VSU. This should allow the OEB to understand how the data inputs a VSU has considered (e.g., customer needs, asset needs, or reliability) leads to the capital expenditure plans. The raw data for the inputs should also be provided (e.g., Section 2.1.3 Poles). A VSU should decide the best way to provide the raw data to present its case.
5.3.1 Planning Process The distributor must provide an overview of its planning process that has informed the preparation of the distributor's five-year capital expenditure plan (a flowchart accompanied by explanatory text may be helpful). A distributor should provide a summary of any important changes to the distributor's asset management process (e.g., enhanced asset data quality or scope, improved analytic tools, process refinements, etc.) since the last DSP filing.	The VSU is to provide an overview of its planning process that has informed the preparation of the DSP. The VSU will note any important changes that have impacted the test year forecast. This section is customizable to each VSU. A VSU should provide how it arrives at its capital expenditure plan. (e.g., Section 1.4 Asset Management Process Flowchart)

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
<u>Process</u> A distributor should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize and pace the execution of investments over the term of the DSP. A distributor should be able to demonstrate that it has considered the correlation between its capital plan and customers' feedback and needs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures (e.g., the risk/benefit of a reactive service transformer replacement program instead of proactively replacing service transformers). A distributor should demonstrate how it does grid optimization using an approach that considers the distributor's whole system. This should include, where applicable, assessing the use of non-wires alternatives, distributed energy resources, cost-effective implementation of distribution improvements affecting reliability and meeting customer needs at acceptable costs to customers, other innovative technologies, and consideration of distribution rate funded Conservation and Demand Management (CDM) activities. A distributor must also demonstrate that it has a planning process for future capacity needs of the distribution system, which must include, among others, increased adoption of electric vehicles. On November 2, 2022, the OEB posted the "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG), which provided guidance in the development of demand forecasts to increase consistency among distributors.14 Distributors should consider this guidance when developing their load forecasts. The guidance recommended a sensitivity analysis to capture uncertainty in the demand forecast and noted "one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends."	If there are no changes to the asset management since the last DSP, then just provide a statement to that affect.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
5.3.2 Overview of Assets Managed Assessment of DSPs requires a comprehensive understanding of all aspects of the assets managed by a distributor. Distributors may vary in terms of the level of detail that they choose to record for their distribution assets, but the expectation is that in assessing the condition of major assets (e.g., station transformers and poles), solely using asset age is not sufficient. A distributor should provide an overview of its distribution service area (e.g., system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for supporting its capital expenditures over the forecast period. A distributor should provide asset information (e.g., asset capacity and utilization; asset condition; asset failures/performance; asset risks; and asset demographics), by major asset type, that may help explain the specific need for the capital expenditures and demonstrate that a distributor has considered all economic alternatives. There should also be a statement as to whether the distributor has had any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the present application. A distributor should also provide a description of whether the distributor is a host distributor (i.e., distributing electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e., receiving electricity at distribution-level voltages from any host distributor(s)). The distributor must identify any embedded and/or host distributor(s). Partially embedded status (i.e., where part of the distributor's network is served by one or more host distributors but where the distributor is also connected to the high voltage transmission network) must be clearly identified, including the percentage of load that is supplied through the host distributor(s). If the distributor is a host distributor, the distributor should identify whether there is	The VSU should describe the assets it manages and describe its service territory (e.g. system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth). The VSU should outline how it determines asset condition for its various asset classes. Overview of assets could include number of each asset, asset demographics, asset utilization/capacity, and asset inspection results. (e.g., Section 1.1 Utility Characteristics and System Configuration and Section 2 Overview of Assets Managed). VSUs should provide the data that they currently use/have. Data that could be provided include asset age, number of assets, asset capacity, asset inspection reports, or asset testing results. ESA inspection reports can be provided as well.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes (such as GS > 50 kW).	
5.3.3 Asset Lifecycle Optimization Policies and Practices An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. The Information provided should be sufficient to show the trade-off between spending on new capital (i.e., replacement) and life-extending refurbishment. A distributor should also be able to demonstrate that it has carried out cost-effective system operations and maintenance (O&M) activities to sustain an asset to the end of its service life (and can include references to the Distribution System Code). A distributor should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how a distributor intends to operate within budget envelopes. For prioritizing capital expenditures, a distributor should help the audience understand the approaches the distributor uses to balance a customer's need for reliability and capital expenditure costs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures. A distributor should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints. A distributor should provide a summary of any important changes to the distributor's asset life optimization policies, processes, and tools since the last DSP filing.	The VSU should describes its processes and practices with respect to making decisions with respect to replacement vs. refurbishment of an asset. Show options that were considered to address asset renewal needs, if available. For system renewal spending, does it maintain or improve reliability and how does this align with what customers want. Considering future capacity requirements could be demonstrated through a load forecast and remaining asset capacity.
5.3.4 CDM Activities to Address System Needs The OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (the CDM Guidelines)16 provide updated OEB guidance	The VSU to provide information if applicable.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
on the role of conservation and demand management (CDM) for rate-regulated electricity distributors, taking into account the provincial 2021-2024 CDM Framework and previous provincial CDM frameworks, and addressing the treatment of CDM activities in distribution rates. The CDM Guidelines require distributors to make reasonable efforts to incorporate CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. CDM activities potentially eligible for distribution rate funding are not limited to energy efficiency programs and include activities that reduce instantaneous electricity demand, including demand response and energy storage. A distributor's DSP should describe how it has taken CDM into consideration in its planning process. The degree of consideration of CDM in meeting system needs should be proportional to the expected benefits, and will likely vary across distributors, taking into account the size and resources of a distributor. CDM will not be a viable alternative for all types of traditional infrastructure investments. Distributors are encouraged to take account of learnings from CDM activities that have been undertaken by other electricity distributors, in Ontario or elsewhere. Distributors may apply to the OEB for funding through distribution rates for CDM activities as specified in the CDM Guidelines. Any application for CDM funding to address system needs must include a consideration of the projected effects on the distribution system on a long-term basis and the forecast expenditures. Distributors must explain the proposed activity in the context of the distributor's DSP, including providing details on the system need that is being addressed, any infrastructure investments that are being avoided or deferred as a result of the CDM activity (could include investments upstream of a distributor), and the prioritization of the proposed CDM activity relative to other system investments in the DSP. Distributors should describe their approach to assessing the benefits and costs of CDM activity. However, the CDM	The VSU should state if CDM is not a viable alternative and provide context as to why (e.g., Section 3.3.7 CDM Activities to Address System Needs).

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
Guidelines recognize that the Framework for Energy Innovation's (FEI) near-term activities include defining an approach to assessing the benefits and costs of distributed energy resources and may apply approaches from the FEI in the future.18	
5.4 Capital Expenditure Plan The capital expenditure plan should set out and comprehensively justify a distributor's proposed expenditures on its distribution system and general plant over a five-year planning period, including investment and asset-related O&M expenditures. A distributor's DSP details the system investment decisions developed on the basis of information derived from its planning process. It is critical that investments be justified in whole or in part by reference to specific aspects of that process. As noted in section 5.2 above, a DSP must include information on the historical and forecast period.	The VSU should provide its capital plan for the test year and four more years. It will outline the issues being addressed by the capital expenditures and point to the supporting information (e.g. ESA 22/04 reports, field reports, audits, special studies). The VSU will provide completed appendices 2-AA and 2-AB. Each investment should tie back to data that is provided as part of the planning process.
The purpose of the information filed under this section is to provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years. Despite the multi-purpose character, a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e., initial or trigger) driver of the investment. For material projects/programs, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or program for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.	The analysis should explain how the VSU performed on previous DSP investments and how this drives future DSP investments (e.g., Section 4.2 Comparison of Planned Expenditures Versus Historical and Section 4.3 Comparison of Historical Actual Expenditures Versus Historical Planned).

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
The distributor must provide completed appendices 2-AA – Capital Projects Table and 2-AB – Capital Expenditure Summary Table along with the following information about a distributor's capital expenditures: • An analysis of a distributor's capital expenditure performance for the DSP's historical period. This should include an explanation of variances by investment or category, including that of actuals versus the OEB-approved/planned amounts for the applicant's last OEB-approved Cost of Service or Custom IR application and DSP (the variance analysis should also include variances in planned and actual volume of work completed). A distributor should particularly explain variances in a given year that are much higher or lower than the historical trend. • An analysis of a distributor's capital expenditures for the DSP's forecast period. For capital investments that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress. • An analysis of capital expenditures in the DSP's forecast period compared to the historical period. • A summary of any important modifications to typical capital programs since the last DSP (e.g., changes to individual asset strategies). System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital investments. A description of the impacts of capital expenditures on O&M must be given for each year, or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital investment. A statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget.	

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
5.4.2 Justifying Capital Expenditures As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate identification, optimization, prioritization, pacing of capital-related expenditures, and how it developed its overall capital budget envelope. A distributor should also keep pace with technological changes and integrate cost-effective innovative investments and traditional planning needs such as load growth, asset condition and reliability. A distributor must not only provide information to justify each individual investment, but also the total amount of its proposed capital expenditures. A distributor should provide context on how its overall capital expenditures over the next five years, as a whole, will achieve the distributor's objectives. Particularly, a distributor should comment on lumpy investment years and rate impacts of capital investments in the long-term.	A VSU can describe the objectives the VSU are planning to achieve and how the VSU plans to achieve them (e.g., Section 4.4 Justifying Capital Expenditures). A VSU should indicate if NWAs were considered and whether it's technically feasible.
Material Investments The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g., unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment. The following are guidelines on the information to be provided for any material investment.	The VSU should provide Material Investment Plans as appropriate. VSU can provide the information they use internally to approve their capital projects/programs. Information does not need to be tailored specifically for the purpose a rate application. If the expected information in the filing requirements do not apply to the proposed capital expenditure the VSU should state so and provide an explanation.

OEB Chapter 5 Filing Requirements	Information that could be included in a VSU DSP to help meet Chapter 5 Filing Requirements
A. General Information on the project/program B. Evaluation criteria and information requirements for each project/program	

VERY SMALL UTILITY INC

Very Small Utility Distribution System Plan

Prepared: December 20xx

Purpose of this example:

1. This sample Distribution System Plan (DSP) is intended to guide electricity distributors with fewer than 5,000 customers in developing their DSP's for purposes of filing cost of service applications.
2. The sample DSP was developed by a working group consisting of representatives from eight very small electricity distributors, the Vulnerable Energy Consumers Coalition and OEB staff.
3. The very small utilities working group identified that while the Chapter 5 Filing Requirements intend to provide the OEB and parties participating in the OEB's adjudicative processes a better understanding of an LDC's distribution system planning, asset management strategy, and decision-making process for capital investments, there is a perception that this requires advanced assessments and data, including the incurrence of significant costs to retain external support. This sample Very Small Utilities Distribution System Plan shows how you can meet all the requirements of the Chapter 5 Filing Requirements and be replicable using internal resources. To this end, the process descriptions and data provided in the sample Very Small Utilities Distribution System Plan are illustrative of what the working group believes a very small utility should be able to provide based on its internal planning processes and internally available data.
4. A good DSP is not dependent on third-party studies or reports. However, you may want to consider such reports depending on what assets you are replacing or adding. For example, if replacing a substation, it may be appropriate to have an Assessment Report of the current substation identifying why this asset needs replacing (oil sample tests, asset failure or degradation, loading issues, safety issues with switchgear, etc)
5. The DSP is the LDCs "story" – clearly explain how the LDC prepares to replace/add assets, the decision process involved and how it impacts your capital investment planning.

6. <u>This is an example only</u> – simply updating this will not mean the DSP is appropriate or relevant to your utility.
7. For additional support or guidance, please contact OEB staff if you have questions as to the sufficiency of information that you plan to file for any particular area within your DSP.

0. CONTENTS

1. ASSET MANAGEMENT PLAN

This Asset Management Plan (AMP, “The Plan”) has been prepared by Very Small Utility Inc. (VSU).

VSU’s AMP supports cost-effective planning that ensures efficiency, dependability, sustainability, and customer value. The AMP documents current practices, policies, and processes. These processes ensure that investment decisions meet VSU's goals cost-effectively and add customer value. VSU follows its AMP to benefit customers. Capital-intensive electricity distributors need sensible capital investments and maintenance programs to maintain network reliability.

Regional planning and local stakeholder interactions are part of VSU's integrated asset planning, prioritization, and management AMP. VSU conducted this AMP concentrating on consumer preferences, operational efficiency, and capital spending value. Details on the specific engagement with these 3rd parties are presented at section 3.3.

VSU used section headers from the AMP example to organize the information. The OEB categorizes investment projects and operations as System Access, System Renewals, System Service, or General Plant. The AMP covers the historical era from [Date] to [Date], the bridge year, the test year, and the projected years. VSU states that this plan's information is current and based on actual expenses as of [Date] and capital expenditure predictions as of [Date]. Project details have been provided for projects over VSU’s materiality threshold of $x as described in Exhibit 1.

VSU states that its asset management fundamentals have not changed since its last AMP in [Date].

1.1 Utility Overview and System Configuration

VSU (VSU) is an embedded distributor within Hydro One's service territory. VSU is a local distribution company servicing approximately 3,800 customers in the Town of Mount Forest, Village of Arthur and the Village of Holstein in southwestern Ontario.

The distributor's service territory is approximately 14 sq. km of medium density urban area and spans across the County of Wellington (Arthur and Mount Forest) and Grey County (Holstein).

The table below shows VSU's principal characteristics, which drive the AMP.

Figure XX - VSU's System Summary

	2019	Supporting Information
Maximum Monthly Peak *(with embedded generation)*	16,845 kW	Month of Peak Demand: January 2019.
Service Area (sq. km)	14	
Kilometers of Line	79	
Total Customers (Metered)		Annual Usage (kWh)
Residential	3,314	25,253,896
General Service <50kW	476	11,138,172
General Service 50-9999 kW	35	18,739,880
General Service 1000-4999 kW	5	42,766,148
Total Number of Metered Accounts	3,830	97,898,096
Total Unmetered Connections		Annual Usage (kWh)
Unmetered Scattered Load	4	6,288
Sentinel Lights	23	19,673
Street Lighting	907	650,270
Total Number of Connections	934	676,231
Annual Metered Consumption (kWh) (not billed, excludes losses for months January to December inclusive)		98,574,327
Annual Generation kWh	392,026 kWh	Annual generated kWh during 2019 from 22 MicroFIT accounts and 1 FIT account
Number of Substations	6	
Wholesale Meter Points	4	
Poles	1,890	
Primary Lines (km)		
Overhead	69	
Underground	10	
Transformers (units)		
Overhead (Polemount)	522	
Underground (Padmount)	145	
44kV Switches Load Break	6	

VSU is an embedded distributor within Hydro One's service territory and is connected to the grid through Hydro One's Transmissions Station feeders:

Figure XX - Transmission Station Feeders

Transformer Substation Owner	Transformer Name	Community Served within Wellington North Power Service Territory
Hydro One Networks Inc.	NA73 - Fergus TS	Urban Area of Arthur
Hydro One Networks Inc.	NA28 - Palmerston TS	Urban Areas of Mount Forest
Hydro One Networks Inc.	NA36 - Hanover TS	Urban Areas of Holstein and Mount Forest

VSU is a registered Market Participant, dealing directly with the Independent Electricity System Operator (IESO) for the electricity which is passed through our distribution system to consumers. As an embedded utility, VSU is billed monthly by Hydro One for all Transmission related charges including Low Voltage. Transmission and Low Voltage charges are passed through to VSU's customers.

VSU's service area consists of 44kV, 8.3kV, and 4.16kV high voltage systems.

VSU has three Hydro One 44kV feeders serving its distribution territory. VSU owns and operates the electricity distribution system in its licensed service area including parts of the Township of Wellington North and the Township of Southgate, serving approximately 3,800 Residential, General Service, Street Lighting, Sentinel Light and Unmetered Scattered Load customers/connections.

VSU's distribution assets include:

- Four municipal distribution stations that steps voltage from 44kV to 4.16kV for distribution within the town of Mount Forest;
- Two municipal distribution stations that steps voltage from 44kV to 4.16kV for distribution within the village of Arthur, and;
- Distribution assets supplied by a Hydro One distribution station which service our customers in the village of Holstein.

VSU receives power from three Hydro One 44kV circuits; one from Fergus TS, one from Palmerston TS and one from Hanover TS. These 44kV circuits are used to supply our distribution assets described above. Electricity is then distributed through VSU's service area of 14 square kilometers through the company's 69km of overhead conductors and 10km of underground cable.

The distribution voltage of 4.16kV is stepped down by approximately 667 transformers, both overhead and underground, to the service voltage provided to our customers. VSU monitors its distribution system using a System Control and Data Acquisition (SCADA) at its main office building at 290 Queen Street West in Mount Forest, Ontario.

VSU owns and maintains approximately 3,800 meters installed on its customers' premises for the purpose of measuring energy consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW demand and kVA, as well as hourly interval data. VSU completed the installation of all of its Residential and General Service <50kW Smart Meters by December 2010 as part of the Province of Ontario's Smart Meter initiative. On June 25, 2008, Ontario Regulation 235/08 was filed by the Ontario Provincial Government giving VSU authorization to proceed with its first phase of Smart Meter installation.

In managing its distribution system assets, VSU's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and worker safety and customer service requirements.

In addition to the capital needs of the network, VSU provides maintenance planning for the assets. VSU's assets fall into two broad categories:

- Distribution Plant - includes assets such as substation building, wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and
- General Plant - includes assets such as, office building and service centre, computer equipment and software. General Plant also includes the company's fleet of six vehicles and stores equipment.

1.2 Asset Management Process Overview

The asset management process is the systematic approach taken by VSU to collect, tabulate and assess information about physical assets, current and future system operating conditions, cyber-security and privacy obligations whilst addressing the LDC's business goals and customer service needs, ensuring investments are planned, paced and prioritized to minimize rate changes to our customers.

This section provides stakeholders with an understanding of VSU's asset management process as well as the relationship between the process and the expenditure decisions that formulate into VSU's capital investment plan.

1.3 Asset Management Objectives

VSU's Asset Management objectives, ranked in order of priority, are:

Priority	Objective
High	Maximizing public and employee safety.
High	Reliability of the distribution system.
High	Consideration of the total cost of the asset to minimize the long-term costs borne by the ratepayers. (Cost-effectiveness to maintain / repair an existing asset (O&M expense) rather than replace with a new asset (CapEx)
High	Minimize environment risks and hazards.
High	Meeting customers' needs and expectations today and for the future.
High	Consideration of acts, regulations, guidelines and good utility practice.
Medium	Provide the shareholders the full regulated return on equity.
Medium	Aligning the DSP with Regional Planning objectives and provincial Long-term Energy Plans.
Low	Facilitating Smart Grid development.
Low	Facilitating new renewable connections.

The comments below provide context on why VSU ranked these Asset Management objectives in this hierarchy of priority:

- **Maximizing public and employee safety:** VSU is committed to operating in an environment that is safe, taking precautions to protect its employees and customers as well as all other stakeholders whether working on site, in the office or at a customer's property. Safety also encompasses cyber-security and the protection of employee and customer personal identifiable information.
- **Reliability of the distribution:** VSU is committed to maintain the reliability of its' system minimizing outages and interruptions. Effective asset management considers asset health as an indicator which may identify assets with a high probability of failure by replacing these assets may reduce the probability of equipment failure.

- **Consideration of the total cost of the asset to minimize the long-term costs borne by the ratepayers:** VSU considers the cost-effectiveness of on-going expenses to maintain / repair an existing asset (O&M expense) rather than replace with a new asset (CapEx).
- **Minimize environment risks and hazards:** VSU recognizes that sustained economic prosperity is only possible if adequate provision is made for the protection of the environment. The utility identifies, assesses and manages the environmental impacts and risks associated with our operational activities (e.g. safe disposal of old PCB transformers).
- **Meeting customers' needs today and for the future:** VSU seeks to fulfill customers' expectations not just today but also the future. For instance, ensuring there is adequate capacity to manage population and industrial growth in our community as demonstrated by the building of a 2nd 44kV feeder in 2016 to provide for planned growth.
- **Consideration of acts, regulations, guidelines and good utility practice:** VSU wants to be recognized as a utility that demonstrates good utility practice whilst adhering to codes, guidelines and mandates set by the authority bodies such as the Ministry of Energy Northern Development and Mines, Ministry of Finance, Ministry of Labour, Measurement Canada, Public Health, the ESA, the OEB and the IESO. Adhering to the acts and regulations is required to hold a distributor's license.
- **Provide the shareholders the full regulated return on equity:** Being owned by Municipal Townships, VSU operates as an efficient business providing regular Promissory Note payments and predictable dividends to its' shareholders to help fund the economic prosperity and well-being of the community in which VSU operates.
- **Aligning the DSP with Regional Planning objectives and provincial Long-term Energy Plans:** VSU participates in the Regional Planning meetings facilitated by the IESO. Given that the aggregated kW demand of the utility represents a very small percentage of the total regional demand requirements, VSU has ranked this of lower importance.
- **Facilitating Smart Grid development:** VSU is monitoring the pilot programs, such as Distributed Energy Resources and battery storage solutions. To date, the utility has received no requests from its customers for this new technology, hence why this is of a lower importance; however VSU will actively support any customer projects if they come forward.
- **Facilitating new renewable connections:** Given that all new renewable contracts were cancelled in 2018, VSU has reduced the importance of connecting green energy and renewable energy sources.

The table below illustrates how VSU's Asset Management objectives relate to the OEB's Renewed Regulatory Framework (RRF) performance outcomes and link to VSU's strategic objectives.

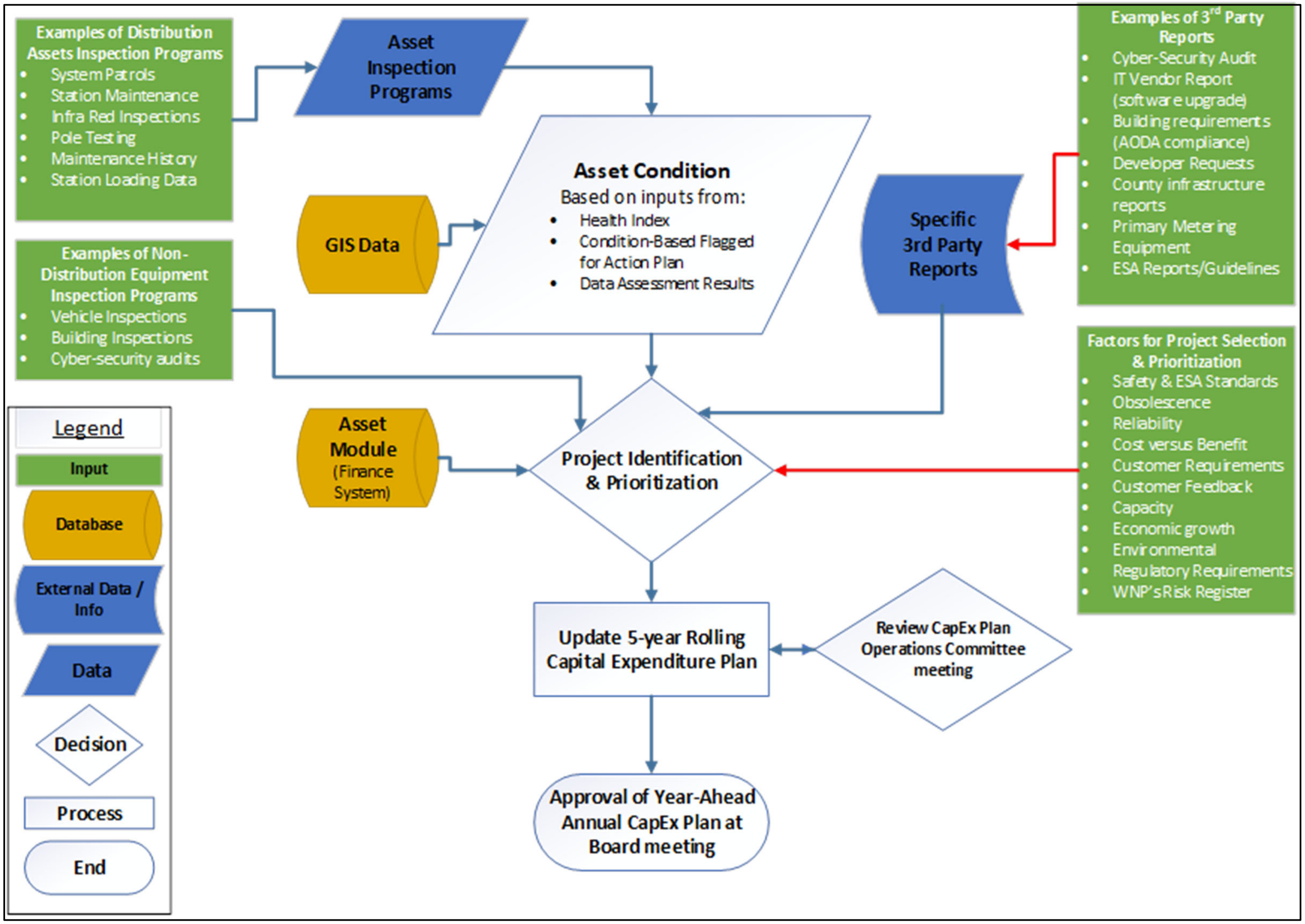
Figure XX - Asset Management Objectives – Renewed Regulatory Framework Outcomes

RRF Performance Outcomes	VSU's Asset Management Objectives	VSU's Strategic Objectives
Customer Focus	○ Meeting customers' needs and expectations today and for the future. ○ Consideration of the total cost of the asset to minimize the long-term costs borne by the ratepayers	• Manage a safe and reliable distribution system in an efficient and cost-effective manner • Provide outstanding customer service.
Operational Effectiveness	○ Reliability of the distribution system. ○ Aligning the DSP with Regional Planning objectives and provincial Long-term Energy Plans. ○ Meeting customers' needs and expectations today and for the future. ○ Consideration of acts, regulations, guidelines and good utility practice.	• Manage a safe and reliable distribution system in an efficient and cost-effective manner.
Public Policy Responsiveness	○ Maximizing public and employee safety. ○ Minimize environment risks and hazards. ○ Consideration of acts, regulations, guidelines and good utility practice. ○ Facilitating Smart Grid development. ○ Facilitating new renewable connections.	• Manage a safe and reliable distribution system in an efficient and cost-effective manner. • Meet all regulatory obligations.
Financial Performance	○ Consideration of the total cost of the asset to minimize the long-term costs borne by the ratepayers ○ Provide the shareholders the full regulated return on equity.	• Manage a safe and reliable distribution system in an efficient and cost-effective manner. • Continue to increase shareholder value.

1.4 Asset Management Process

The flowchart below summarizes the core components of VSU's Asset Management Process for prioritization of investments:

Figure XX - Asset Management Process Flowchart



1.5 Investment by Category

In developing its long-term AMP, VSU's objective is to make timely investments in infrastructure to ensure its distribution system continues to deliver power at the quality and reliability levels required by its customers. Details on the forecast capital expenses can be seen in Section 5.

VSU tracks its capital spending in both the traditional system USoA and the RRFE categories (System Access, System Renewal, System Service, and General Plant).

The table below provides the Historical Investments VSU has made between [Date] and projected for [Date].

Figure XX - Planned Capital Investment: AMP 2015 versus AMP 2020

Previous Capital Expenditure Plan - 2016-2020							
Category	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**	**Yearly Avg**
System Access	$55,000	$240,000	$240,000	$240,000	$60,000	$835,001	$167,000
System Renewal	$90,000	$390,000	$1,932,000	$290,000	$450,000	$3,152,002	$630,400
System Service	$1,373,217	$0	$0	$0	$0	$1,373,218	$274,644
General Plant	$75,694	$138,670	$24,470	$421,850	$453,000	$1,113,685	$222,737
Total	**$1,593,911**	**$768,670**	**$2,196,470**	**$951,850**	**$963,000**	**$6,473,906**	$1,294,781

Capital Expenditure Plan - 2021-2025							
Category	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**	**Yearly Avg**
System Access	$70,000	$70,000	$70,000	$70,000	$85,000	$365,001	$73,000
System Renewal	$340,000	$265,000	$265,000	$315,000	$315,000	$1,500,002	$300,000
System Service	$26,500	$18,500	$21,000	$81,500	$14,000	$161,500	$32,300
General Plant	$190,500	$598,050	$151,450	$150,800	$179,500	$1,270,302	$254,060
Total	**$627,000**	**$951,550**	**$507,450**	**$617,300**	**$593,500**	**$3,296,805**	**$659,361**

- VSU has a planning process and controls in place that are adequate and sufficient for the size of the utility.
- VSU's total capital expenditure for the forward looking 5 years of 2021-2025 is lower when compared to the actual capital expenditure spent for the historical period of 2016 to 2020.
- A review of the utility's performance and outcomes from the last AMP filed in 2020 covering the period 2015 to 2020 shows the utility spent prudently and slightly below the capital expenditure budget.
- No capital investment is required to address reliability concerns or capacity as articulated in the sections of "Performance Measurement for Continuous Improvement" and "System Capability Assessment for Renewable Energy Generation".
- The reported "Service Quality Metrics" for the utility are meeting or exceeding the OEB's targets. Therefore, no capital investment is required to improve or maintain the servicing requirements of the utility's customers.
- Interaction and coordination with third parties in preparing this AMP has helped shape this investment plan.

2. OVERVIEW OF ASSETS MANAGED

2.1.1 MS Municipal Substations

VSU owns and operates [#] municipal sub-stations. The station data is summarized below in the table below. They are located within the Village of [Village] and Town of [Town]. Each station is controlled by appropriately rated MS Transformers, MS Switchgear and MS Load Switches. All stations are monitored through VSU's SCADA system.

Figure XX - Substation Data

Station	Year	Voltage	Transformer Size	Number of Feeders	HV Protection	LV Protection
Mount Forest MS1	1986	44 - 4.16kV	5.0MVA	4	SMD-2C 80A Type E Fuse	SM-5 400A Type E Fuse
Mount Forest MS2	2014	44 - 4.16kV	5.0MVA	4	SMD-2C 100A Type E Fuse	SEL 351R Recloser & Relay
Mount Forest MS3	2018	44 - 4.16kV	5.0MVA	4	SMD-2C 100A Type E Fuse	SEL 351R Recloser & Relay
Mount Forest MS4	1964	44 - 4.16kV	2.0MVA	4 ①	SMD-2C 40A Type E Fuse	SM-5 400A Type E Fuse
Arthur MS5	1994	44 - 4.16kV	5.0MVA	3	SMD-2C 100A Type E Fuse	SM-5 400A Type E Fuse
Arthur MS6	2010	44 - 4.16kV	5.0MVA	2	SMD-2C 100A Type E Fuse	SM-5 400A Type E Fuse

① Feeder F2 is the only feeder connected and in service

As summarized in the table below, each feeder in [Village] and [Town] are controlled by either a fused or non-fused metal enclosed gang operated load break switch. VSU's MS1, MS4, MS5 and MS6 feeders are fused. MS2 and MS3 also have remote controlled reclosers for the 4.16kV feeders.

Figure XX - Substation Protection

Station	44kV Primary	4.16kV Feeder	Protection
MS1	Gang Operated Air Load Break Switch	Gang Operated Metal Enclosed Fused Load Break Switch	Fused
MS2	Gang Operated Metal Enclosed Load Break Switch	Gang Operated Metal Enclosed Non-Fused Load Break Switch	Reclosers x4
MS3	Gang Operated Air Load Break Switch	Gang Operated Metal Enclosed Non-Fused Load Break Switch	Reclosers x4
MS4	Gang Operated Air Load Break Switch	Gang Operated Metal Enclosed Fused Load Break Switch	Fused
MS5	Gang Operated Air Load Break Switch	Gang Operated Metal Enclosed Fused Load Break Switch	Fused
MS6	Gang Operated Air Load Break Switch	Gang Operated Metal Enclosed Fused Load Break Switch	Fused

[Town]

The Town of [Town] is supplied by two 44kV HONI M Class feeders. One feeder is from Hanover TS and is identified as 36M5. The seconder feeder from Palmerston, identified as 28M2 was constructed and energized in 2016 due to a capacity issue with the 36M5 as presented in VSU's 2015 rate application.

The 44kV feeders running through the town of [Town] supply four 44 to 4.16kV municipal stations owned and operated by VSU, as well as three private stations owned by businesses.

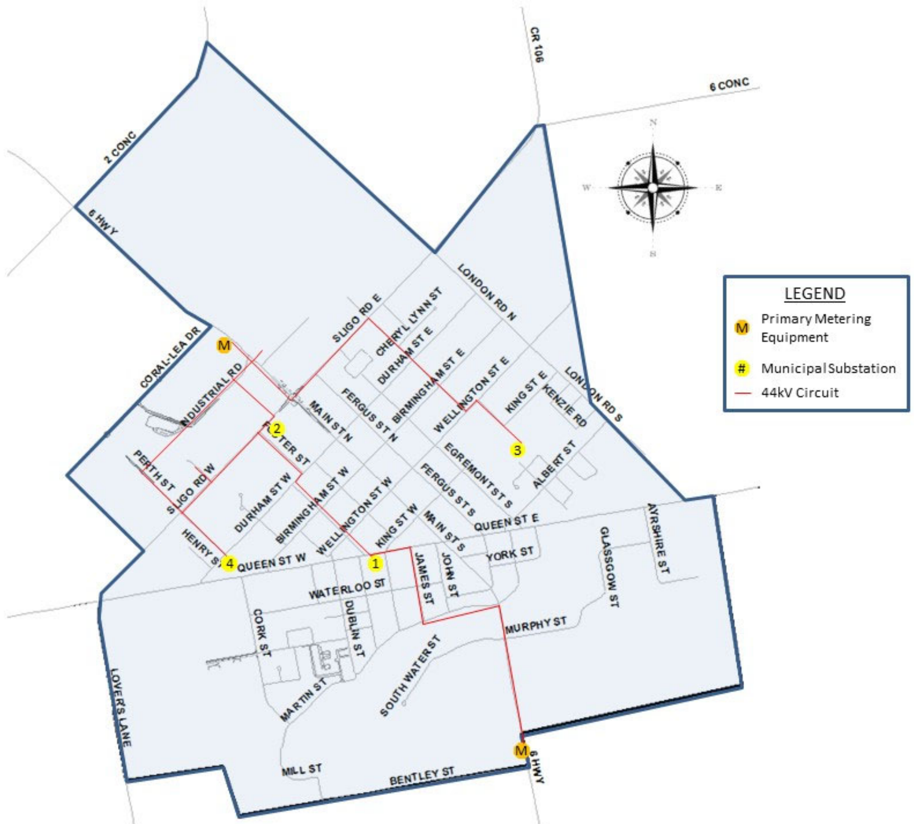
The four municipal stations, fed by the 44kV sub-transmission system, are being replaced in a proactive manner as they reach their end of life. Municipal Station Two "MS2" was replaced in 2014 and Municipal Station Three "MS3" was replaced in 2018.

The table below shows information regarding the substation transformers. The transformers ages are as at 2023 and the peak load data of the transformer was recorded during the period January 1, 2023 to December 31, 2023.

Figure XX - Substation Transformer Data

Substation	Transformer Installed	Transformer Age	Transformer Nameplate	Peak Load
MS1 – Mount Forest	1986	37	5 MVA	48%
MS2 – Mount Forest	2014	7	5 MVA	56%
MS3 – Mount Forest	2018	5	5 MVA	53%
MS4 – Mount Forest	1964	59	2 MVA	26%
MS5 – Arthur	1994	29	5 MVA	52%
MS6 – Arthur	2010	13	5 MVA	51%

Table 5 - 44kV System in [Town]



[Town] - Substation MS1

VSU MS1 provides service to the south portion of [Town] and serves primarily residential customers. The transformer is a 5.0 MVA unit with four 4.16kV feeders. The station is currently protected by SMD-2C, 80A Type E fuses on the HV side and by SM-5 400A Type E fuses on the LV side. The power transformer and switchgear at this station is stamped with a manufactured date of 1986.

VSU has redundancy built into its distribution feeder network as follows:

Distribution Feeder	Contingency Feeder (Switch)
MS1 F1	MS4 F2 (SPM046 at Cork & Queen W)
MS1 F2	MS1 F3 (SPM019 at 340 John St) or MS3 F2 (LB4-001 at Parkside Dr)
MS1 F3	MS1 F2 (SPM019 at 340 John St) or MS3 F2 (LB4-002 at Peel St)
MS1 F4	MS2 F3 (SPM016 at Normanby & Wellington W)

[Town] – Substation MS2

VSU MS2 provides service to the central-north portion of [Town] and serves both residential and small business customers. The station was rebuilt in 2014 and consists of a 44kV enclosed fused load break switch, 5MVA power transformer, a 5 bay 4.16kV switchgear assembly, four (4) auto-recloser units one per feeder, pad mount station service transformer and a 10 x 10 control enclosure.

VSU has redundancy built into its distribution feeder network as follows:

Distribution Feeder	Contingency Feeder (Switch)
MS2 F1	MS3 F4 (LB4-003 at Church St)
MS2 F2	MS3 F4 (SPM047 on Mount Forest Dr)
MS2 F3	MS1 F4 (SPM016 on Normanby St)
MS2 F4	MS4 F2 (SPM022 on Perth St)

Add details as applicable.

2.1.1.1 MS Switchgear

The average age of the switchgear in the MS substations is 25 years. The actual age of each substation's switchgear is shown below:

Figure XX - MS Switchgear Data

[see 2.1.3 Poles as example. Information may vary depending on what a very small utility has available.]

2.1.1.2 MS Load Switches

The average age of the Load Switches in the MS substations is 25 years. The actual age of each substation's Load Switches is shown below:

Figure XX - MS Load Switches Data

[see 2.1.3 Poles as example. Information may vary depending on what a very small utility has available.]

2.1.2 Transformers

VSU has 145 Pad-Mounted Transformers. The average age of the Pad-Mounted Transformers is 23 years. The actual age of each substation's Pad-Mounted Transformers is shown below:

Figure XX - Pad Mounted Transformer Data

[see 2.1.3 Poles as example. Information may vary depending on what a very small utility has available.]

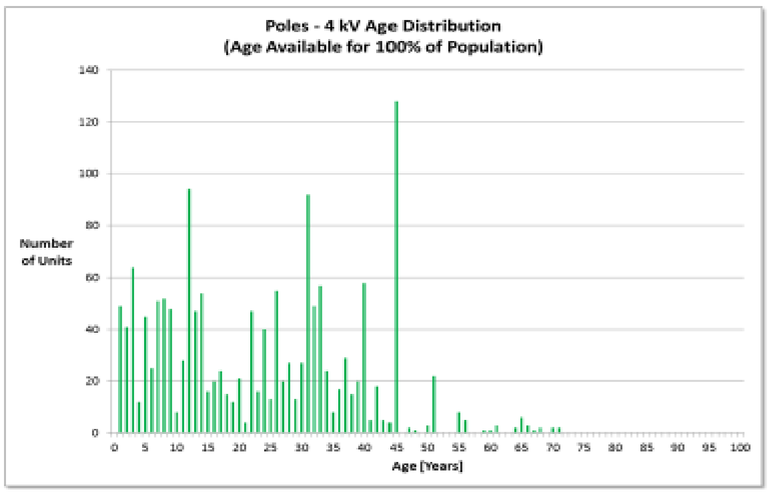
VSU has 458 single-phase Pole-Mounted Transformers and 64 three-phase Pole-Mounted Transformers with an average of 25 years and 18 years respectively. The chart below shows the actual ages:

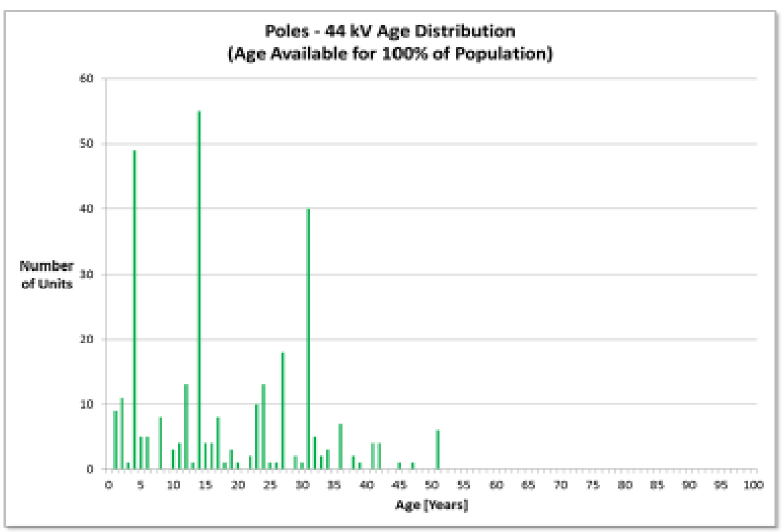
Figure XX - Pole Mounted Transformer Data

2.1.3 Poles

VSU has 1,581 4 kV poles and 309 44kV poles with an average of 23 years and 18 years respectively. The chart below shows the pole ages:

Figure XX - Pole Data





VSU completes system patrols on a yearly basis. The patrol includes a visual inspection of the poles looking for visible signs of damage or a leaning pole. In addition to visual inspections, wooden poles are tested every three years meeting the requirements of the DSC.

From 2019, VSU started testing wooden poles using a Polux pole tester to measure the density of the wood (force from driving in a screw to the pole) and moisture which could lead to deterioration and rotting.

The charts below show the result of the Polux pole testing for the latest years of 2019 and 2020:

Figure XX – 4 kV Pole Test Results

4 kV Poles		Test Year: 2019		
	# of Poles	*Test Result*		
Vintage	Tested	Green	Amber	Red
1940	2	1	1	0
1950	6	4	1	1
1960	8	7	1	0
1970	58	54	1	3
1980	52	51	0	1
1990	85	81	2	2
2000	56	56	0	0
2010	72	71	1	0
2020				
Total	339	325	7	7
Total Pole Population	1,581			
Poles Tested as % of Pole Population	21%	21%	0%	0%

4 kV Poles		Test Year: 2020		
	# of Poles	*Test Result*		
Vintage	Tested	Green	Amber	Red
1940	3	3	0	0
1950	5	3	2	0
1960	8	8	0	0
1970	68	63	1	4
1980	87	81	6	0
1990	96	95	0	1
2000	127	123	2	2
2010	92	91	1	0
2020	0	0	0	0
Total	486	467	12	7
Total Pole Population	1,583			
Poles Tested as % of Pole Population	31%	30%	1%	0%

Figure XX – 44 kV Pole Test Results

44 kV Poles		Test Year: 2019		
	# of Poles	*Test Result*		
Vintage	Tested	Green	Amber	Red
1960	1	4	0	0
1970	2	3	0	0
1980	2	1	1	0
1990	18	18	0	0
2000	15	15	0	0
2010	38	38	0	0
2020				
Total	76	79	1	0
Total Pole Population	309			
Poles Tested as % of Pole Population	25%	26%	0%	0%

44 kV Poles		Test Year: 2020		
	# of Poles	*Test Result*		
Vintage	Tested	Green	Amber	Red
1960	1	1	0	0
1970	2	2	0	0
1980	3	3	0	0
1990	21	20	1	0
2000	18	18	0	0
2010	48	48	0	0
2020	0	0	0	0
Total	93	92	1	0
Total Pole Population	309			
Poles Tested as % of Pole Population	30%	30%	0%	0%

The test result of:

1. Green indicates there were no issues identified.
2. Amber indicates data showing either a higher level of moisture or less dense than expected, therefore these poles will be monitored by VSU and inspected yearly to check for signs of further deterioration.
3. Red indicates data showing the density of pole was deteriorating above the standards and/or there were signs of rot.

For poles with a Red test result, these poles have been flagged and included in the VSU's annual pole-replacement program for years 2021 and 2022.

2.1.4 Meters

VSU owns and maintains approximately 3,800 meters installed on its customers' premises for the purpose of measuring energy consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW demand and kVA, as well as hourly interval data. VSU invoices its customers monthly, on a calendar billing cycle.

Wholesale Metering

VSU receives its power from HONI by three 44kV sub-transmission feeders and an 8.3kV distribution feeder. The four feeders are metered at the borders of Arthur (44kV), Mount Forest (44kV x 2) and Holstein (8.3kV).

Retail Metering

VSU uses Elster meters across its service territory and has contractual agreements with:

- Rodan Energy Solutions as the LDC's Meter Services Provider (MSP);
- Savage Data Systems for Operational Data Store (ODS) which involves the validation, estimation and editing (VEE) of metered data;
- UtiliSmart as the LDC's appointed Advanced Metering Infrastructure (AMI) Operator and;
- UtiliSmart for settlement services and web presentment of Wholesale, Retail, Embedded Generation interval data.

Smart Meters

All Smart metered interval data (Residential and General Service <50kW customers) is provided to the Meter Data Management and Repository (MDM/R) who process, store and manage the data. The MDM/R metered data is shared with the LDC who, with support from Savage Data Systems, validates the interval usage and ensures completeness of data.

In 2017, 2018 and 2019, VSU sampled a population of Smart Meters for accuracy in accordance with Measurement Canada requirements due to the meters approaching a seal life of 10 years. The results from the sampling were good meaning the Smart meters were sealed for use for a further 6 years.

In its' 2015 DSP, VSU had planned to replace all its' Smart meters during 2017 to 2019 as the meters were approaching 10 years old. VSU opted to re-verify its' Smart meters (i.e. extend their life rather than replace).

MicroFIT/FIT

MicroFIT/FIT interval metered data follows the same routine process as Smart meters, with the exception that the data is not sent to or stored in the MDM/R.

Over 50kW Meters

General Service 50-999kW (GS50-999kW) and General Service 1,000-4999kW (GS1000-4999kW) interval metered data and meter readings are transmitted by telecommunications each night. Each meter is dialed, and the data is downloaded into MV90 and shared with Utilismart.

MIST Meter

VSU is compliant to the "Metering Inside the Settlement Timeframe" (MIST) requirement[1]. All existing services with a monthly average peak demand during a calendar year of over 50kW has had a MIST meter installed. VSU started installing MIST meters to customers in its' General Service 50-999kW rate class in September 2017 and completed the project in early January 2018. Any new services with a projected average peak demand of over 50kW during a calendar year had a MIST meter installed.

Meter Capital

VSU has included the following its' 2021-2025 capital investment program:

- Meter Replacement: Replacement of failed Smart meters (i.e. typically due to condensation).
- Wholesale Metering: - replacement of or refurbishment of wholesale meters and equipment in accordance with MSP's Wholesale Metering Program. This is listed under the item "Wholesale Metering Program".

[1] Section 5.1.3 of the DSC & EB-2013-011: A distributor shall (a) install a MIST meter on any new installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW; and (b) have until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during a calendar year of over 50 kW.

3. PLANNING PROCESS

In managing its' distribution system assets, VSU's core objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. VSU is committed to providing our customers with an economical, safe, reliable supply of electricity and enabling our community to be energy efficient.

VSU has regulatory obligations and responsibilities to the Ontario Energy Board (OEB) and the Electrical Safety Authority (ESA). VSU must also comply with Ontario Regulation 22/04 Electrical Distribution Safety and is subject to annual Audits and Declaration of Compliance. VSU makes investments to focuses on maintaining its performance levels reported to the OEB and maintaining compliant with ESA codes and regulations.

VSU's guiding principles regarding Capital Expenditure are two-fold:

1) To replace assets before they fail; and
2) To replace assets at the end of their useful life.

VSU maintains a list of potential future CapEx projects and programs. The utility assesses these proposed projects taking into consideration factors including:

- Safety, ESA Standards – does the LDC need to make changes to its distribution system to comply with latest ESA standards. For example, replacing "Delta" connections with "Wye" grounded connections.
- Reliability – are there assets that are failing that should be replaced to maintain reliability (e.g. a leaking transformer).
- Cost versus Benefit - the cost-effectiveness of on-going expenses to maintain / repair an existing asset (O&M expense) rather than replace with a new asset (CapEx). This data is provided from the utility's financial system.
- Programs to replace certain end-of-life assets in advance of failure are also given high priority to allow for a paced and sustainable replacement program that "levels" annual spending by asset type to the extent possible. For instance, annual replacement of poles and transformers that have been identified as having a poor health index score.
- Customer Requirements and Requests – Priority in project selection is given to non-discretionary projects that are required to meet regulatory obligations, for example, service connections and plant relocations.
- Customer Feedback – from surveys and customer meetings, for instance the installation of a 2nd 44kV feeder to the Town of Mount Forest in 2016 to provide for additional capacity and further switching opportunities in the event of a loss of supply.
- Economic growth – does the project support growth in our community, for instance working with builders and developers to "right-size" connection requirements for housing projects.
- Regulatory Requirements – for example the installation of MIST meters to comply with the Distribution System Code Section 5.1.3 and OEB's requirement EB-2013-0311. Cyber-security / Privacy of Data – programs that increase the protection of VSU's IT and OT operating systems and platforms as well as initiatives that enhance the protection of data and information.

Updating Rolling 5-year Capital Expenditure Plan:

From the list of potential future projects, VSU updates its rolling 5-year capital plan. This contains projects that have been prioritized by year that can now be scoped to provide an estimate for the work. Examples include:

- Pole replacement jobs can be entered into VSU's job estimation tool to provide budget amount needed to undertake the project.
- Requests for quotes can be sent to IT providers, the MSP for wholesale metering projects and manufacturers for bucket-truck replacement.

- **Review – Operations Committee Meeting**
  VSU's Operations Committee meeting meets every quarter. The Committee consists of Directors and Staff. One of the meeting's mandates is to review next year's capital spending, reviewing each project and its' proposed cost. The objective is for the Committee to make a recommendation for the VSU Board of Directors to approve the Capital Expenditure (CapEx) budget.

- **Approval of CapEx Budget**
  With a recommendation from the Operations Committee, the Board of Directors review the CapEx budget for the year ahead. This is typically at October's Board meeting with the CEO/President discussing each project, its scope and why it is needed and why it is a priority. It is envisaged that the Board approve the annual capital plan at November's Board meeting.

The projects included in the capital expenditure plan can be grouped into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure:

a) System Access
b) System Renewal
c) System Service
d) General Plant

System Access

For proposed investments under the System Access category, the key drivers in the case of VSU include:

- Customer service requests for new customer connections
- Customer requests for modifications or amendments from the LDC's distribution equipment up to the entry point of the property.
- Customer requests for load expansion at existing commercial and industrial customers.
- Third party infrastructure developments requiring system plant relocates; and

- Mandated service obligations, such as revenue metering.

As discussed earlier, over the past 5 years, VSU has experienced a stable customer-base with the number of metered customer accounts increasing at less than an average of 1% per year. A modest number of requests are received each year for newly constructed homes. As demonstrated by the LDC's service quality statistics, VSU's performance in connecting new services is above the minimum target set by the regulator.

Road widening projects in the LDC's service area require relocation of some power distribution lines each year. Such projects requiring capital investments by VSU are anticipated to continue throughout the next five years.

All residential and general service customers have been equipped with smart meters. VSU completed sampling for meter resealing and re-verification in 2017, 2018 and 2019. The LDC is planning to replace smart meters commencing in 2026 when meters will have reached their 15-year useful asset life.

System Renewal

VSU maintains inspections and reports for major assets that includes age, operating conditions, results of visual inspections and non-destructive testing and identifies the assets in "very poor condition" and "poor condition" that present unacceptably high risk of failure in service.

Over the past five years, VSU has been systematically planning and implementing investments into asset renewal projects to replace the assets that have reached the end of their useful service life, by prioritizing investments into those assets with the highest impact on reliability and safety when they fail in service. Since the in-service failure of substation assets has the highest impact on reliability and safety, a majority of the asset renewal investments during the past five years have focussed on the replacement of substations.

Distribution system renewal projects during the next five years also include renewal of high-risk assets on both the overhead and underground distribution system. By taking into account the results of testing, patrols and service age, assets which are in poor condition are identified and included in this distribution plan for renewal.

VSU has not had extensive failure issues with the overhead pole mounted distribution transformers. Like most distribution utilities, VSU manages this asset category using a reactive replacement strategy, i.e. replacement of transformers upon failure, unless inspections identify transformers that present safety risks. In the case of our pad mounted transformer, VSU plans to replace any that are considered a live front transformer which is considered a risk to worker safety. This is a relatively small population typically found in neighbourhoods built in the 1960s.

System Service

Projects in the System Service category are driven by the need to alleviate capacity constraints due to load growth. The projects in this category also include capital investments aimed at improving system operations, reliability and efficiencies through voltage upgrades, distribution automation and intelligent devices or equipment, all aimed at enhancing customer value and operational effectiveness.

During the next five years, no capacity constraints are anticipated on the distribution system requiring investments into capacity upgrades. VSU's smart grid development initiative, involving equipping all the distribution stations with automated feeder reclosers and supervisory control and data acquisition (SCADA) system, has been started. Two of the stations are now equipped with automated and remote controlled reclosers, protected through SEL relays, allowing all features of the SCADA system to be fully utilized. Smart grid development initiative also includes upgrade and renewal of revenue meters to comply with the regulations.

General Plant

The capital investments under this category include investments into motor vehicle fleet, equipment and tools, buildings and facilities, computer hardware, software systems and system supervisory equipment. These investments are driven by the objectives to improve employee safety as well as maintain worker productivity and operating efficiency.

VSU's capital budget broadly consists of the following categories:

- **Annual activities:** Replacement of assets identified as in poor condition as a result of inspections.

- **New services:** This item is non-discretionary and unpredictable, VSU typically use the last 3 years of actual CapEx spent on new services/upgrades to form a view for the next 5 years. The table below shows VSU's CapEx spent for the past 3 years:

  Figure XX - New Service / Upgrades CapEx History

	2017	2018	2019	3-yr Average
New Service & Upgrade	$44,017	$99,257	$50,913	$64,729

  In its CapEx plan for years 2021-2025, VSU have used an annual budget amount of $60,000 for this item.

- **Metering**: Replacement of failed or broken Smart meters is treated as a non-discretionary item. The removed meters are scrapped because the one-year warranty period has passed and it is more cost-effective to purchase a new meter (at approximately $115 per meter) compared to sending the meter back to the manufacturer for investigation (approximate cost $200).

- **Metering Reseal or Replacement:** In 2017, VSU started the reverification of its Smart meters. This involves sending a sample of meters, based on the year of manufacturer, for verification according to Measurement Canada standards. The sampling was approved and meter populations were resealed for six years.

- **Pole line rebuild**: Specific projects to replace a number of poles due to their condition following routine inspections and / or due to other factors as cited in the business justification (for example: road-widening project initiated by another party or replacing 30 ft poles with 45 ft poles to meet ESA clearance requirements.)

- **Smart Technology:** Typically includes projects to automate the distribution system or provide additional data or control to SCADA.

- **Underground projects:** Specific projects to rebuild underground assets which are in poor condition.

- **IT/Cyber-security:** Specific projects to replace equipment or harden IT security and enhance data privacy.

- **Wholesale Metering Program:** Recommendations from VSU's Meter Service Provider (MSP) to replace Primary Metering Equipment (PME i.e. revenue meters) to maintain accurate reporting of metered demand and usage to the IESO; this includes meters, metering equipment, modems, and cabinets.

- **Shop tools:** Replacement of tools and safety equipment to support day-to-day operations activities.

- **Transport:** Replacement of fleet vehicles based on usage, age and on-going maintenance costs.

- **Building renovation:** Repairs to buildings and replacement of office furniture. VSU treats this category as discretionary.

3.1 Asset Lifecycle Optimization and Practices

Stations, poles, primary and secondary wires, transformers, and switches are the key distribution assets of VSU. In compliance with the Distribution System Code, all distribution plant undergoes inspections, at the very least, every three years.

To guarantee the safe and dependable operation of the distribution system, VSU carries out a variety of maintenance and operational tasks. Thermographic inspection, line patrols, pole inspections, and substation maintenance are a few of these tasks.

Inspections are audited annually within the utility's Ontario Regulation 22/04 audit.

In compliance with Sections 4 and 5 of Regulation 22/04, the Distribution System Code (DSC), and ESA Guidelines, VSU has established and adheres to inspection and maintenance protocols.

All line patrols and inspections are documented. The asset inspection data and available device information is used to support maintenance activities and capital expense planning. Specific inspection and testing processes are dependent on the asset type.

With the use of their GIS asset management tool, VSU fully expects to continue to correlate asset condition data, asset maintenance and replacement expenditures and the resulting system performance indicators. These systems and their information will collaborate and support the experience of VSU staff.

3.1.1 MS Municipal Station

VSU conducts monthly visual inspections of its Municipal Substations in accordance with its Policy 2040 Distribution Substation Inspections. An Infrared Inspection of the station is completed on a yearly basis. In addition, a third-party testing agency, is contracted to test and perform maintenance on the substation every three years. VSU meets the requirements of the DSC as well as ESA Regulation 22/04.

Each substation is visually inspected every month by VSU's Operations staff. The visual inspection includes looking for signs of oil leakage, corrosion or damage to equipment (switchgear) and damage to perimeter safety fence.

In addition to visual inspection VSU covers all of its transformers in its annual infra-red inspections. These inspections look for hot spots on transformers and their primary/secondary connections. And, on a rotating basis of every three years, each substation is inspected by Company ABC, a 3rd party retained by VSU. Company ABC conduct substation oil sample testing. The latest results are summarized in the table below:

Figure XX - Substation Test Results

Substation	Oil Sample Test Results	Test Date	Infra-Red Test	Infra-Red Test Result	Test Date
MS1	Oil appears to be in good condition. There is no parameter that is out of the ordinary or cause for concern.	2018	Barrel fuses and pot head terminations to transformer	Appears to be operating normally	2020
MS2	Oil appears to be in good condition. There is no parameter that is out of the ordinary or cause for concern.	2018	Barrel fuses and pot head terminations to transformer	Appears to be operating normally	2020
MS3	Oil appears to have been changed since last analyzed. There is no parameter that is out of the ordinary or cause for concern.	2019	Barrel fuses and pot head terminations to transformer	Appears to be operating normally	2020
MS4	Oil appears to be in good condition. There is no parameter that is out of the ordinary or cause for concern.	2019	Barrel fuses and pot head terminations to transformer	Appears to be operating normally	2020
MS5	Oil appears to have been changed since last analyzed. There is no parameter that is out of the ordinary or cause for concern.	2020	Rear of barrel fuses and pot head terminations to transformer	Appears to be operating normally	2020
MS6	Oil appears to be in good condition. There is no parameter that is out of the ordinary or cause for concern.	2020	Load breaking switch and pot head terminations to transformer	Appears to be operating normally	2020

3.1.2 Transformers:

The inspection of transformers includes:

Pole Mounted:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map.
- Leaking oil
- Flashed or cracked insulators.
- Contamination/discolouration of bushings
- Ground lead attachments
- Damaged disconnect switches or lightning arresters.
- Ground wire on arresters unattached

Pad Mounted:

- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage.
- Grading changes
- Access changes (Shrubs, trees etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid Damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General Condition

VSU performs maintenance on any transformers which are identified by either visual or infra-red inspection as needing work. This work may include replacement of connections if found to be hot, painting or replacement of unit if leaking.

3.1.3 Poles

VSU completes system patrols on a yearly basis. The patrol includes a visual inspection of the poles looking for visible signs of damage or a leaning pole. In addition to visual inspections, poles are tested every three years, using a polux pole tester, meeting the requirements of the DSC.

3.1.4 Switch and Cutout

VSU has been conducting switch inspection on all Gang operated switches every three years. Each year these switches are inspected for damage and wear.

Additionally Visual inspections are carried out on all switches as part of the Line Patrols and Thermographic Inspection Program.

- Bent, Broken bushings and cutouts.
- Damaged lightning arresters
- Ground wire on arresters unattached

Inspection of underground switching equipment is also carried out on a three-year cycle, in accordance with the Distribution System Code and includes the following:

- Paint condition and corrosion
- Check for lock and penta bolt in place or damage.
- Grading changes
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General Condition

Records of inspection, recorded and stored in a digital format shall be reviewed and priority of follow up scheduling of maintenance and/or corrective action activities will be completed accordingly.

Non-gang operated switches are visually inspected according to the inspection program and are maintained as required.

VSU replaces cutouts upon failure and pre-emptively replaces porcelain cutouts with polymer cutouts when already working on the pole upon which the cutout is mounted.

3.1.5 Meters

All maintenance activities related to meters follow the requirements of Measurement Canada guidelines.

3.1.6 Conductor

Line patrols are conducted annually in accordance with the VSU Procedures. The line patrols include a visual inspection of the following:

Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

General Conditions and Vegetation

- Leaning or broken “danger” trees
- Growth into line of “climbing” plants.
- Accessibility compromised
- Vines or bush growth interference (line clearance)
- Bird or animal nests

Vegetation and Right of Way

- Accessibility compromised.
- Grade changes that could expose cable.
- Excessive vegetation on right of way

3.1.7 Line Patrol

VSU patrols its entire distribution system every three years, in accordance with the VSU Engineering and Operations Policy #18 as well as the Distribution System Code. Distribution system line patrols are tracked using the "Record of Inspection". VSU line staff performs line patrols. VSU staff also inspects the condition of lines whenever they are working in an area.

In addition to (over and above the DSC requirements) the DSC requirements, VSU encourages its staff to continually inspect their local work area. Due to the size of the service area and the repetitive attention to localized areas in the day-to-day activities, attention is given to small issues before they can become problems. This proactive approach has resulted in a wealth of detail regarding system conditions that can be used in system planning to allow staff to proactively and predictively resolve system issues before they become problems.

These scans, performed by a 3rd party allow VSU to identify problem areas and turn unplanned outages into shorter planned outages or eliminate the outage completely. This is reflected in both VSU system reliability statistics and in the customer survey responses and feedback.

3.1.8 Overhead System - Line-Trimming

As part of the regular maintenance plan for the pole line assets, VSU schedules regular tree-trimming activities, as described below:

Vegetation and Right of Way control is required under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. VSU has a relatively heavy mature tree cover where overhead hydro lines are in the proximity to trees. Tree contact with energized lines can cause the following:

- Interruption of power due to short circuit to ground or between phases.
- Damage to conductors, hardware and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees.
- Danger of electric shock potential from electricity energizing vegetation

Care must be taken to balance the requirements of customers and stakeholders and safe and reliable operation of the distribution system.

Tree Trimming inspections have been incorporated into the other inspection programs included in this plan and additional verification will be performed by work crews in the area in which regular work is performed.

To mitigate direct contact between trees and distribution assets, VSU conducts tree trimming in accordance with the VSU Procedures. Depending on the size, shape and growth pattern of each tree species, the tree trimmers remove sufficient material from the tree to limit the possibility of contact during high wind situations. The VSU service area is trimmed on a two-year cycle as per formal requirements and lead hand judgment. This work is primarily carried out by VSU employees, but contractors may be hired, based on cost and availability of resources.

All debris is removed, and the site is returned to as-found condition. Any pole line damage or anomaly noticed by the tree trimming crew is reported to VSU"s Chief Operating Officer for remedial action.

3.1.9 Asset Life

VSU has adopted depreciation rates based on the Kinectrics Asset Depreciation Study. The utility is not proposing any changes to the depreciate rates for any assets.

3.2 Performance Measurement for Continuous Improvement

This section captures the results of VSUI's annual reliability performance, whose purpose is to maintain activities and assist in establishing priorities for capital investments while mindful of its ability to meet all the customer's needs in a sustainable manner.

VSU has a small service territory and, as such, does not have the workload to sustain a complement of staff to provide all the functions of the utility in-house. It acquires the services it needs on a contract basis. As a result, engineering studies are contracted out, as are the system construction, maintenance, emergency trouble-calls, and responses and billing. The overall management, purchasing, finance functions, and customer service are maintained in-house.

This approach works well for VSU from a cost management and timing perspective for the physical work and the timely financial billing or project costing. Project work is contracted on a fixed price basis. Maintenance and repair work is based on unit prices negotiated in advance and authorized before the work is started except in the case of emergency work after hours.

This approach also means that VSU does not incur fixed or ongoing costs for engineering work or power system work unless work is done. The work is defined, and the costs are contained. In this way, cost efficiency and work performance are kept high.

The cost of electricity is an essential matter for VSU's customers. In their 2020 Customer Survey the response to the question, "To what extent, if any, is the cost of Electrical service a strain on your household budget?" was that 70% of those surveyed responded with either "A great deal" or "Some." Hence, the cost is of importance to VSU's customers. Most of the general comments were also with respect to the cost of electricity.

This indicates that VSU's efforts in controlling its rates align with its customer's needs.

3.2.1 Reliability Indices

VSU records and reports annually the following Service Reliability Indices:

SAIDI = System Average Interruption Duration Index = <u>Total Customer-Hours of Interruptions</u>

Total Customers Served

SAIFI = System Average Interruption Frequency Index = = $\frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$

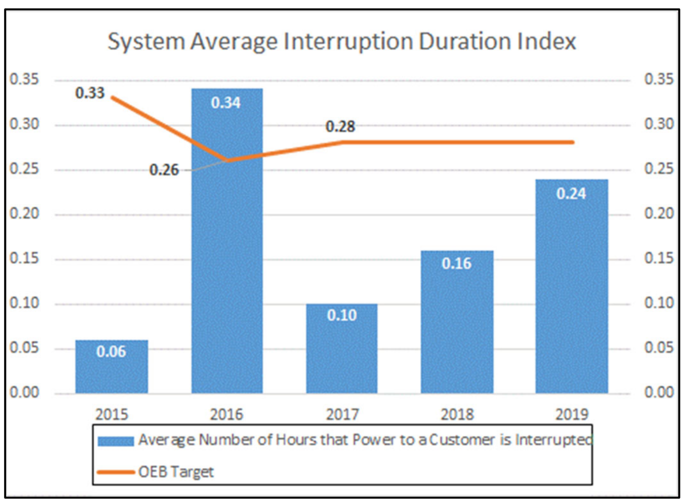
VSU records the power outage start time as the time the LDC received communication from a customer reporting the interruption.

The OEB expects a utility to keep its hours of interruption within the range of its 5-year historical performance average.

System Average Interruption Duration Index ("SAIDI")

VSU's 5-year historical performance is currently 0.28 average hours based on the utility's average SAIDI for years 2011 to 2015. The figure below illustrates VSU's adjusted SAIDI values for the period 2015 to 2019 plotted against the 5-year historical performance (OEB's expected target for the utility)[2].

Figure XX - Adjusted SAIDI Performance for VSU



In 2016, VSU achieved 0.34 average hours of interrupted power which is above the utility's target of 0.26 average hours. The 2016 above-target result was predominately due to a major capital project of a new 2nd line 44kV feeder in Mount Forest which required more planned power outages than prior years to safely complete pole-line construction work. For all other years, VSU's SAIDI performance has been below the OEB's target.

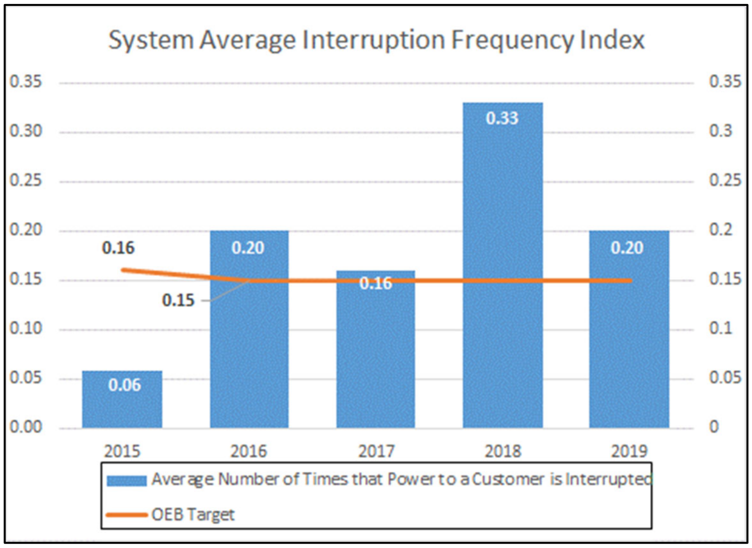
System Average Interruption Frequency Index ("SAIFI")

[2] OEB Target: 2015 target was the average reported SAIDI for 2010-2014 (i.e. 0.33); 2016-2020 target was the average reported SAIDI for 2010-2014 with the removal of Major Events during this period.

The figure below illustrates VSU's adjusted[3] SAIFI values for the period 2015 to 2019 plotted against the 5-year historical performance (OEB's expected target for the utility)[4]. VSU's 5-year performance is currently 0.15 times based on the utility's average SAIFI for years 2011 to 2015.

[3] Adjusted = Power outages due to Loss of Supply (HONI) and Major Events are not included in the SAIDI calculation.
[4] OEB Target: 2015's target was the average reported SAIDI for 2010-2014 (i.e. 0.16); 2016's target was the average reported SAIDI for 2010-2014 with the removal of Major Events during this period (i.e. 0.15) as required as per the OEB's letter March 13, 2017 "Reporting of Customer Interruptions Data Related to Major Events")

Figure XX - Adjusted SAIFI Performance for VSU



As noted previously, the 2016 above-target result was predominately due to a major capital project of a new 2nd line 44kV feeder in Mount Forest which required more planned power outages than prior years to safely complete pole-line construction work.

In 2018, VSU experienced interrupted power 0.33 times which is above the range of the utility's 5-year average SAIFI performance of 0.15. This frequency of increased power outages was primarily a consequence of:

- On 12th April 2018, there were unplanned power outages due to distribution equipment failure that affected approx. 25% of our customers.
- Planned projects, such as pole-line replacement in a residential area, will result in residential customers experiencing a brief power outage to enable crews to work safely rather than work on a "live system". VSU counts each residential property individually when there is a power-outage.

For 2019, VSU's SAIFI was 0.20 times which is marginally above the range of the utility's 5-year average SAIFI performance of 0.15. Again, this frequency of increased power outages was primarily a consequence of planned projects, such as pole-line replacement in a residential area, will result in residential customers experiencing a brief power outage to enable crews to work safely rather than work on a "live system". VSU counts each residential property individually when there is a power-outage.

3.2.1.1 Cause Codes for Power Interruptions

The table below summarizes all causes of power interruptions experienced by VSU customers for the period 2015 to 2019:

Figure XX - All Causes of Power Interruptions (2015-2019)

		2015		2016		2017		2018		2019	
Code	Description	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours
1	Scheduled	154	146.87	346	209.72	529	276.17	248	187.12	291	199.80
2	Loss of Supply	17,728	34,856.75	10,230	16,330.52	14,745	14,028.70	10,554	15,919.37	7,115	2,288.58
3	Tree Contact	0	0.00	28	7.93	1	1.00	1	6.13	1	1.57
4	Lightning	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
5	Defective Equipment	30	42.97	54	55.37	38	36.32	875	247.70	40	84.63
6	Weather	10	12.33	609	2,216.20	22	40.17	92	114.70	48	244.27
7	Adverse Environment	0	0.00	0	0.00	0	0.00	12	2.23	0	0.00
8	Human Element	6	1.50	1	94.67	0	0.00	0	0.00	0	0.00
9	Animal	2	8.53	1	0.98	9	20.33	42	41.32	16	93.32
10	Other	16	26.02	1	0.17	1	0.03	0	0.00	356	305.37
	Major Event			0.00	0.00	0.00	0.00	5,417	21,875.83	0.00	0.00
	Total	17,946	35,095	11,270	18,916	15,345	14,403	17,241	38,394	7,867	3,218

Figure XX – Count of All Causes of Power Interruptions (2015-2019)

Code	Description	2015	2016	2017	2018	2019
1	Scheduled	22	60	88	56	51
2	Loss of Supply	9	5	8	12	5
3	Tree Contact	0	1	1	1	1
4	Lightning	0	0	0	0	0
5	Defective Equipment	15	13	10	13	17
6	Weather	1	17	2	3	2
7	Adverse Environment	0	0	0	2	0
8	Human Element	1	1	0	0	0
9	Animal	3	1	2	6	3
10	Other	2	1	1	0	4
	Major Event		0	0	2	0
	Total	53	99	112	95	83

As illustrated in the table above, the majority of power interruptions over the historical period have been caused by loss of supply. In 2018, the “Major Event” was a loss of supply occurring on August 29th and September 1st – this is discussed below.

Based upon the historic reliability performance of VSU as noted above, the utility has no reliability issues or concerns. And, VSU has received no complaints about reliability. Therefore, VSU is proposing no capital investment is required in its assets of distribution system.

3.2.1.2 Major Events

VSU determines if a power outage should be classified and reported as a Major Event by following "The IEEE Standard 1366"[5] calculation of:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

A Major Event Day (MED) is a day which the daily system SAIDI exceeds threshold value, T_{MED}. VSU calculates the daily SAIDI and any day where the daily SAIDI is greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a Major Event.

Since the introduction of Major Event reporting by the OEB, VSU has experienced 3 major events as summarized below:

Figure XX - Major Events (2016-2019)

Date	**Cause**	**Customers Interrupted**	**Total Customer Hours of Interruption**	**SAIDI** (in minutes)	T_{MED}	**MERR Filed**
March 25th 2016	Weather	284	1,321	21.16	15.76	No
August 29th 2018	Loss of Supply	2,702	14,636	229.10	13.64	Yes
September 1st 2018	Loss of Supply	2,715	7,240	113.15	13.64	Yes

VSU uses the IEEE Standard 1366 used to derive the threshold for the Major Event.

Notes:

i. March 25th 2016: A Major Event Response Reporting (MERR) was not filed with the regulator as this event occurred before the OEB released the MERR reporting requirements on May 3rd 2016.
The ice-storm that occurred on the evening of March 24th 2016 and into the early hours of March 25th 2016 was reported over the two separate dates. The storm resulted in 2,198 total customer hours of interruption and affected 602 customers (approx. 16% of VSU's customer-base). The SAIDI (in minutes) for March 24th 2016 was 14.05 which is below the T_{MED} threshold of 15.76.

ii. T_{MED} is based on the average daily SAIDI of the previous 5 years. (For instance, 2016's T_{MED} is based on the average daily SAIDI for years 2011 to 2015).

Based upon the historic Major Events experienced by VSU as noted above, the utility has no reliability issues or concerns. And, VSU has received no complaints about reliability. Therefore, VSU is proposing no capital investment is required in its assets of distribution system to improve reliability. VSU has planned its capital investments to maintain current reliability performance.

[5] IEEE Std 1366-2020 – IEEE Guide for Electric Power Distribution Reliability Indices", Section 3.5 Major Event Day Classification

3.3 Coordinated Planning with Third Parties

Coordinated Planning with Third Parties

This AMP has been prepared through a coordinated planning process with the following stakeholders:

a) Independent Electricity Systems Operator (IESO).
b) Regionally interconnected Transmitters and Distributors – Hydro One.
c) Regional and municipal governments.
d) Telecommunication Entities.
e) Others

3.3.1 IESO & Regional Planning

The IESO has segmented the Province of Ontario into 21 electricity regions placed into three groups. VSU's service territory resides in 2 planning groups as illustrated in the table below:

Figure XX - Regional Planning for Group 1 and Group 3

Planning Group	Zone	VSU's Service Areas	Station Names	Connection
Group 1	Kitchener-Waterloo-Cambridge-Guelph	Arthur	Fergus TS	Dx
Group 3	Greater Bruce-Huron	Mount Forest Holstein	Hanover TS Palmerston TS	Dx Dx

Source: http://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Overview

VSU did not initiate the consultation but has participated in both the Group 1 and Group 3 Regional Planning meetings facilitated by the IESO. The meetings involve the IESO, Hydro One (Transmitter), Hydro One (Distributor) and LDCs as assigned to the regional group.

There is no final deliverable from these consultations and the processes is on-going, with VSU participating the meetings. VSU is not aware of any REG investments in its services area.

For the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region, latest planning information can be found on the IESO's website at:

https://www.ieso.ca/en/Get-Involved/Regional-Planning/Southwest-Ontario/Kitchener-Waterloo-Cambridge-Guelph

It is anticipated the Integrated Regional Resource Plan (IRRP) will be released in 2021. To the best of VSU's knowledge, there are no impacts to the distributor.

VSU, Hydro One, and IESO are part of the Grey Bruce Study area. The most recent study, entitled Needs Assessment, and a Regional Infrastructure, was conducted in September of 2021. Its scope included:

- Review and reaffirm needs/plans identified in the previous report; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region; and
- Develop options for need(s) and/or preferred plan or recommend which conditions require further assessment/regional coordination.

VSU's primary input into the report concerns the load forecast, which assists Hydro One with its regional planning. Nothing flagged in this report affected the work planned or capital investment in the near future.

For the Greater Bruce-Huron region, latest planning information can be found on the IESO's website at:

https://www.ieso.ca/en/Get-Involved/Regional-Planning/Southwest-Ontario/Greater-Bruce-Huron

It is anticipated the Integrated Regional Resource Plan (IRRP) will be released in 2021. To the best of VSU's knowledge, there are no impacts to the distributor.

VSU confirms, to the best of its knowledge, there are no inconsistencies between its AMP and any current Regional Plans.

3.3.2 Hydro One

VSU shares a feeder with Hydro One's distribution business. Hydro One is the owner of the transformer station and feeder to the limits of VSU service area, at which point, all distribution lines within the utility's service area are owned and operated by VSU.

VSU has an excellent working relationship with Hydro One. Any items or concerns the LDC has are raised with Hydro One's Account Executive who, as part of their portfolio, manages the relationship with VSU. Typically, Hydro One's Account Executive and VSU meet once a year to discuss any on-going concerns or to provide a "heads-up" of future events that may affect either party. This meeting or consultation may be initiated by either party.

VSU is not forecasting or planning any changes to the load, renewable generation connections and the utility has been actively participating in regional planning meetings.

With no changes noted, HONI Transmission and HONI Distributor are not required to review or comment on VSU's AMP.

3.3.3 Municipal Government

The lower-tier municipal government in VSU's service area is the Township of Wellington North. The Township of Wellington North relies on the County of Wellington, upper-tier regional government, for planning activities. The utility receives information from the Township of Wellington North and VSU has a copy of the County's and the Township's most recent long-term planning documents.

The Township shares its' capital investment budget with VSU which is updated every year. This provides an opportunity for the LDC to review third-party infrastructure projects (such as water and sewer renewal or re-surfacing roads) where VSU may need to move or relocate assets (i.e. poles or pad mount transformers.)

The Township has created the "Wellington North Community Growth Plan" (the "Growth Plan") to provide direction for policy development and decision-making regarding land development, growth-related investments and initiatives to contribute to planning for positive growth and change in Wellington North. As per this report:

"While the Plan is comprehensive in nature, its purpose is to outline recommendations for the direction and management of potential future urban growth, which will occur primarily in the urban areas of Arthur and Mount Forest."

The urban areas of Arthur and Mount Forest are serviced by VSU.

VSU participated in the creation of the "Growth Plan", with the CEO/President of the utility included in the "Community Growth Plan Steering Committee". Of interest to VSU:

a) The forecast directs the most population and housing growth to Mount Forest as the largest urban area with the greatest servicing capacity available for future development, with an average annual growth rate of 3.1%. Mount Forest's average annual growth rate for the period of 2011 to 2016 was 1.6%.
b) The forecast population growth in Arthur reflects an average 1.8% population from 2016 to 2036. After 2036, the forecast reflects no further residential growth, which would result in a small decline in Arthur's population.
c) The "Growth Report" mentions an increase in intensification (i.e. number of people per hectare). New residential properties to accommodate the increasing population will be available by:
    i. Re-developing vacant land;
    ii. Re-zoning some urban land from commercial/industrial to residential; and
    iii. New residential properties to be built upwards (i.e. more multi-unit apartment buildings).

VSU is preparing for population and household growth by:

a) Load Capacity - MS4 substation in Mount Forest:

VSU's MS4 substation in Mount Forest is currently operating with minimal load. This substation can handle additional load should there be an immediate increase in demand. MS4 substation is circa 1970s; however, because there is minimal load on this station, it is not a critical asset for replacement.

Concerning demand, there is sufficient capacity to handle increased demand as projected by the Township and the County. VSU is already working with Developers to review new-subdivisions and servicing requirements.

3.3.4 Telecommunication Entities.

VSU has two telecommunications entities that operate in its service territory, Bell Communications and Wightman Communication Ltd. VSU met with Bell Communications in March 2020 and Wightman Communication Ltd in June 2020. At these meetings, both telecommunication entities confirmed they have no projects in VSU's service areas relating to “Supporting Broadband and Infrastructure Expansion Act, 2021”. And, furthermore, the telecommunication entities confirmed that fibre has been installed across VSU's service territory and, to their best of their knowledge, there are no broadband connectivity projects scheduled in these areas for the period of 2021-2025.

Based on the above information, VSU has not included any capital investment expenditure for “Broadband Expansion” telecommunications entities and has no specific requests from the two telecommunications entities.

3.3.5 Local Planning Coordination

VSU is part of a circulation list that receives regular updates from the municipality concerning zoning amendments and new projects in the service territory. When VSU receives such notice, the utility can comment and meet with the developer to discuss the project and impact, if any.

As a fully embedded distributor, VSU is also in constant contact with the account executive at Hydro One. The communication flows both ways in that both utilities keep each other informed of any occurring issue that could affect either utility. Both utilities communicate or meet regularly to share information on project and construction planning.

3.3.6 Development Planning

VSU is in constant contact with developers within its territory. Once VSU is informed of new developments within its service area, it becomes an active planning participant and will meet with developers to discuss and plan the project. There has been a significant recent development in the VSU service area and the area that borders Hydro One's territory. Coordination of services beyond its service territory requires joint planning with Hydro One Networks.

Since its last AMP in 2017, two new developments have been energized:

- Subdivision [Name] Phase II (2021) -54 lots
- Subdivision [Name] Phase III (2021) -42 lots

Two new subdivisions project are planned for 2022, requiring a Service Area Amendment.

Subdivision [Name] Phase III (Approximately 65 lots) is scheduled to start in July 2022.

A capital expenditure estimation of $115,000.00 is forecast for this project.

Subdivision [Name] (Approximately 250 lots) is also expected to start in July 2022. The new development cuts across Hydro One's territory and VSU's territory. The developer has requested that VSU be the service provider for the new subdivision. Discussions are still ongoing. VSU and the developer expect a formal decision and arrangement by March 2022. The outcome of these discussions is expected to be formalized in the Spring of 2022.

3.3.7 CDM Activities to Address System Needs

The OEB's Conservation and Demand Management (CDM) Guidelines require distributors to make reasonable efforts to incorporate consideration of CDM into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure.

VSU has identified that projects in the System Service category driven by the need to alleviate capacity constraints due to load growth are the most likely candidates for a CDM activity. In particular, VSU has concluded, given the assets it manages, that the only likely use case for CDM is to potentially avoid or defer a capacity upgrade (driven by load growth) to one of its municipal substations. Should VSU identify a need to upgrade the load-carrying capacity at one of its substations (prior to technical end of life), a CDM activity will be further considered to potentially avoid or defer this upgrade.

VSU has concluded that during the next five years, no capacity constraints are anticipated on the distribution system requiring investments into capacity upgrades. VSU tracks maximum power flow at each substation in relation to rated capacity to proactively inform it of potential future constraints and allow time for consideration of a CDM activity should a need arise.

As part of its participation in the regional planning process, VSU also stays informed regarding any CDM activities (or other non-wires alternatives)[6] that may be under consideration by the IESO to address regional needs within the planning region(s) encompassing VSU's service territory, and whether any impact on VSU is anticipated.

[6] IESO, Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives

4. CAPITAL EXPENDITURE PLAN

4.1 Capital Expenditure Summary

The table below illustrates the programs included in VSU's planned 5-year capital investment forecast as programs:

Figure XX - CapEx Plan 2021 to 2025

	Category	2021	2022	2023	2024	2025
Project Name #1: Special Projects						
No special projects (e.g. substation replacement)		$0	$0	$0	$0	$0
Sub-Total		**$0**	**$0**	**$0**	**$0**	**$0**
Project Name #2: Annual Projects						
Pole & Transformer Replacements	*System Renewal*	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000
New Services	*System Access*	$ 60,000	$ 60,000	$ 60,000	$ 60,000	$ 60,000
Meter Replacements	*System Renewal*	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Smart Meter Re-seal and Reverification	*System Access*	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 25,000
Sub-Total		**$150,000**	**$150,000**	**$150,000**	**$150,000**	**$165,000**
Project Name #3: Construction Projects						
Pole-Line Re-build projects	*System Renewal*	$185,000	$ 185,000	$ 185,000	$ 185,000	$ 185,000
Underground Projects	*System Renewal*	$ 75,000			$ 50,000	$ 50,000
Sub-Total		**$260,000**	**$185,000**	**$185,000**	**$235,000**	**$235,000**
Project Name #4: SCADA& Smart Technology						
SCADA	*System Service*	$ 15,000			$ 66,500	
SMART Technology	*System Service*	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Sub-Total		**$25,000**	**$10,000**	**$10,000**	**$76,500**	**$10,000**
Project Name #4: General Plant						
Wholesale Metering Program	*General Plant*	$ 1,500	$ 8,500	$ 11,000	$ 5,000	$ 4,000
Computer Hardware/Software/Cyber-Security	*General Plant*	$138,000	$ 170,550	$ 103,950	$ 83,300	$ 132,000
Building Renovation & Accessibility Compliance	*General Plant*	$ 50,000			$ 65,000	
Fleet Replacement	*General Plant*		$ 425,000	$ 45,000		$ 45,000
Tools	*General Plant*	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500
Sub-Total		**$192,000**	**$606,550**	**$162,450**	**$155,800**	**$183,500**
Total		**$627,000**	**$951,550**	**$507,450**	**$617,300**	**$593,500**
Capital Contributions		$ (20,000)	$ (20,000)	$ (20,000)	$ (20,000)	$ (20,000)
Net Capital Expenditures		**$607,000**	**$931,550**	**$487,450**	**$597,300**	**$573,500**
System O & M		$705,000	$ 719,000	$ 733,000	$ 748,000	$ 763,000

VSU's capital expenditures by OEB investment category are:

Figure XX - OEB Categorization: CapEx Plan 2021 to 2025

Category	2021	2022	2023	2024	2025
System Access	$70,000	$70,000	$70,000	$70,000	$85,000
System Renewal	$340,000	$265,000	$265,000	$315,000	$315,000
System Service	$26,500	$18,500	$21,000	$81,500	$14,000
General Plant	$190,500	$598,050	$151,450	$150,800	$179,500
Total CapEx	**$627,000**	**$951,550**	**$507,450**	**$617,300**	**$593,500**
Capital Contributions	($20,000)	($20,000)	($20,000)	($20,000)	($20,000)
Net Capital Expenditures	**$607,000**	**$931,550**	**$487,450**	**$597,300**	**$573,500**
O & M	**$705,000**	**$719,000**	**$733,000**	**$748,000**	**$763,000**

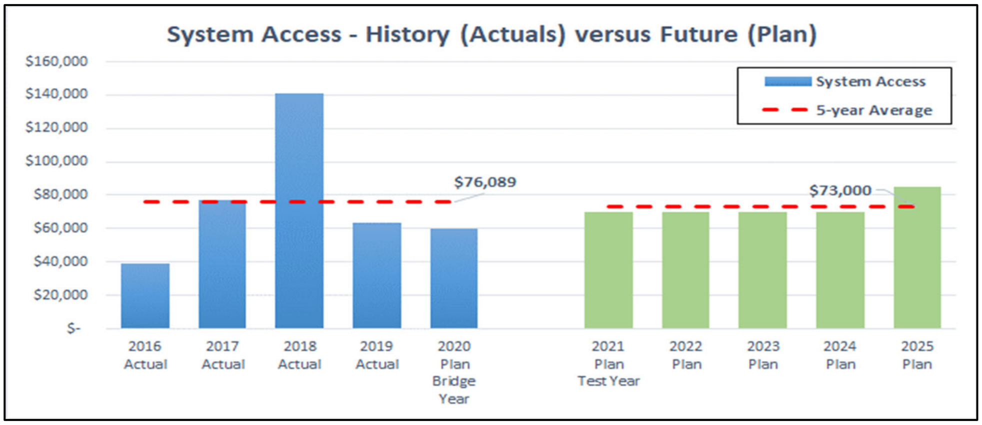
VSU confirms that Capital Expenditures do not affect Operations and Maintenance expenses.

4.2 Comparison of Planned Expenditures versus Historical

System Access

The chart below illustrates how much VSU spent (Actuals) on System Access over the historic period of 2016-2020 compared to the LDC's forecasted CapEx plan for this investment category:

Figure XX - System Access – Historic Actuals versus Planned – Gross CapEx



The 5-year plan for System Access expenditures is consistent with historical spending and activities in this category; the 5-year historic average is $76,089 with the projected 5-year planned yearly average at $73,000.

The table below illustrates VSU's Net Capital Expenditures, both historically and for the proposed planning period, taking into consideration Capital Contributions from customers and developers for System Access Projects:

Figure XX - System Access – Historic Actuals versus Planned – Net CapEx

Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Plan Bridge Year	2021 Plan Test Year	2022 Plan	2023 Plan	2024 Plan	2025 Plan
System Access	$ 38,722	$ 77,353	$ 140,741	$ 63,630	$ 60,000	$70,000	$70,000	$70,000	$70,000	$85,000
Cap Contribution	$ (5,922)	$ (13,041)	$ (26,532)	$ (19,805)	$ (18,800)	$ (20,000)	$ (20,000)	$ (20,000)	$ (20,000)	$ (20,000)
Net Capital	**$ 32,800**	**$ 64,312**	**$ 114,209**	**$ 43,825**	**$ 41,200**	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ 65,000**

As noted in the section "Coordinated Planning with Third Parties", the Township of Wellington North anticipates growth within its municipal area and there has been an increase in planning and re-zoning applications submitted. Consequently, VSU is forecasting an increase in Capital Contributions received in the planning period 2021 to 2025 compared to the previous planning cycle period.

In 2018, new service connections were unusually high compared to prior years which explains the spike in System Access costs for this year. The table below illustrates the number of new connections connected over the past 5 years:

Figure XX - Number of New Services Connected

	2015	2016	2017	2018	2019	5-year Average
New Services Connected	19	22	35	49	42	33

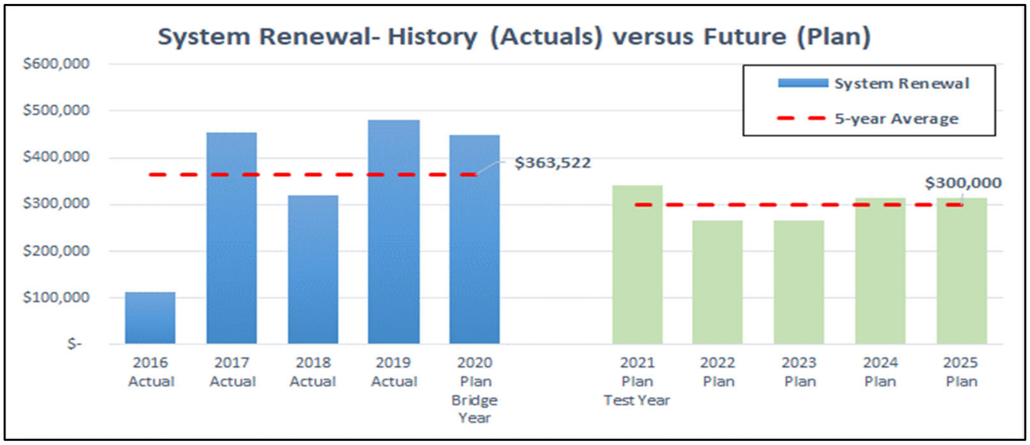
As well as new services and upgrades, included in this investment category is "meter seal or replace". VSU will continue during 2021 to 2025 with reverification and resealing of Smart meters before expiry of their 10-year meter seal date. In 2025, the LDC has planned for an additional $15,000 as it is beginning meter replacements.

Overall, forecasted costs for this investment category are based on historical averages with no large expenditures anticipated.

System Renewal

The chart below illustrates how much VSU spent (Actuals) on System Renewal over the historic period of 2016-2020 compared to the LDC's forecasted CapEx plan for this investment category:

Figure XX - System Renewal – Historic Actuals versus Planned CapEx



In the above chart, for 2018, VSU has removed the CapEx cost of $1,692,893 for the replacement of a substation (MS4) as this was a "special" project, which if included, would have distorted the 5-year average history trend (i.e. increased from $363,522 to $702,101). However, it should be noted that in 2018, VSU had non-discretionary projects that it deferred so as to accommodate the substation replacement. Using an historic average of $363,522 as a comparison, VSU's 5-year forward plan yearly average of $300,000 is consistent.

Included in this investment category are:

- Pole-line rebuild projects – provisioning $185,000 each year for 2021-2025.
- Underground asset replacement projects in 2021, 2024 and 2025.
- Metering - replacement of broken / failed Smart meters – provisioning $25,000 per year.
- Replacement of "poor health" poles and transformers. VSU is budgeting $55,000 per year for 2021 to 2025 to replace poles that through testing have been found to be rotted. The table below illustrates the amount of CapEx spent by VSU on replacing "poor health" poles and transformers over the past 3 years"

Figure XX - CapEx Cost for Replacement of Poor Health Poles & Transformers

	2017	2018	2019	3-year Average

Replacement of "Poor Health" Poles & Transformers	$70,668	$69,163	$49,230	$63,020

Investment in System Renewal projects compliments customers' expectations as per the survey conducted by VSU in Q4 of 2019 which included customers ranking their top "high priority investments". As noted in the customer survey responses, the top "high priority" statements for investment prioritization was "Maintaining and upgrading equipment" (as ranked by 76% of all respondents).

The table below illustrates VSU's Net Capital Expenditures, both historically and for the proposed planning period. As per previous years, VSU is not anticipating any Capital Contributions for Service Renewal projects in the forecast plan period of 2021-2025:

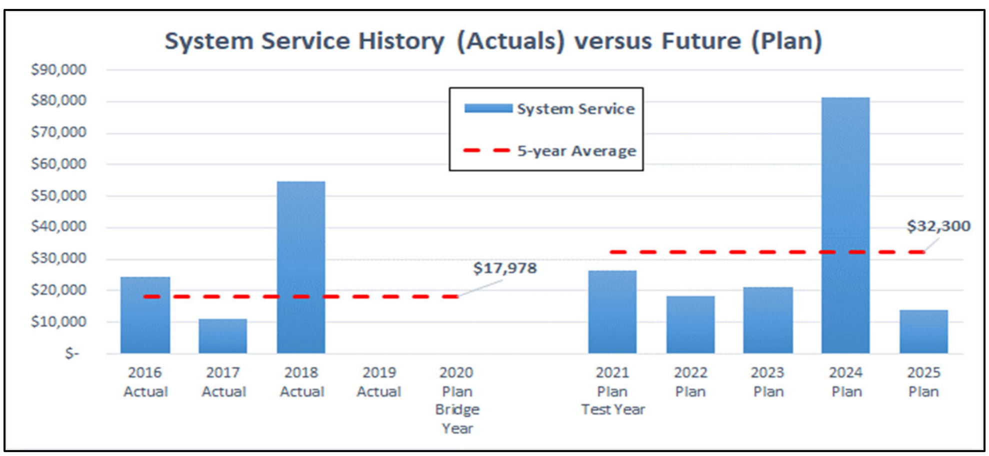
Figure XX - System Renewal – Historic Actuals versus Planned – Net CapEx

Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Plan Bridge Year	2021 Plan Test Year	2022 Plan	2023 Plan	2024 Plan	2025 Plan
System Renewal	$ 113,170	$454,353	$ 319,293	$480,796	$ 450,000	$340,000	$265,000	$265,000	$315,000	$315,000
Cap Contribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Capital	**$ 113,170**	**$454,353**	**$ 319,293**	**$480,796**	**$ 450,000**	**$340,000**	**$265,000**	**$265,000**	**$315,000**	**$315,000**

System Service

The chart below illustrates how much VSU spent (Actuals) on System Service over the historic period of 2016-2020 compared to the LDC's forecasted CapEx plan for this investment category:

Figure XX - System Service – Historic Actuals versus Planned CapEx



In the above chart, for 2016, VSU has removed the CapEx cost for the construction, build and energization of a new 2nd line 44kV feeder to Mount Forest as this was a "special" project, which if included, would have distorted the 5-year average history trend. (It should be noted that in 2016, VSU had non-discretionary projects that it deferred so as to accommodate the build of the new 2nd line 44kV feeder.)

Using an historic average of $17,978 as a comparison, VSU's 5-year forward plan yearly average of $32,300 is 80% above the historic yearly average. The main reason for this increase is the upgrade of the SCADA system planned for 2024 with a budgeted amount of $66,500. This SCADA system upgrade is required to meet latest software capability and security protocols, given that at this time, the current software will be almost ten years old.

Aside of this SCADA software project in 2024, System Service project yearly expenditures are fairly consistent and comprise of the following items:

- SCADA – communications software upgrade (planned for 2021).
- Wholesale Metering Program – to replace primary revenue meters, cabinets and communication software to ensure connectivity to IESO. Different components of the Wholesale Metering equipment will be upgraded during the period 2021-2025.
- Smart Technology – annual investments to upgrade elements of the distribution system to connect with SCADA or provide demand loading information.

The table below illustrates VSU's Net Capital Expenditures, both historically and for the proposed planning period. As per previous years, VSU is not anticipating any Capital Contributions for System Service projects in the forecast plan period of 2021-2025:

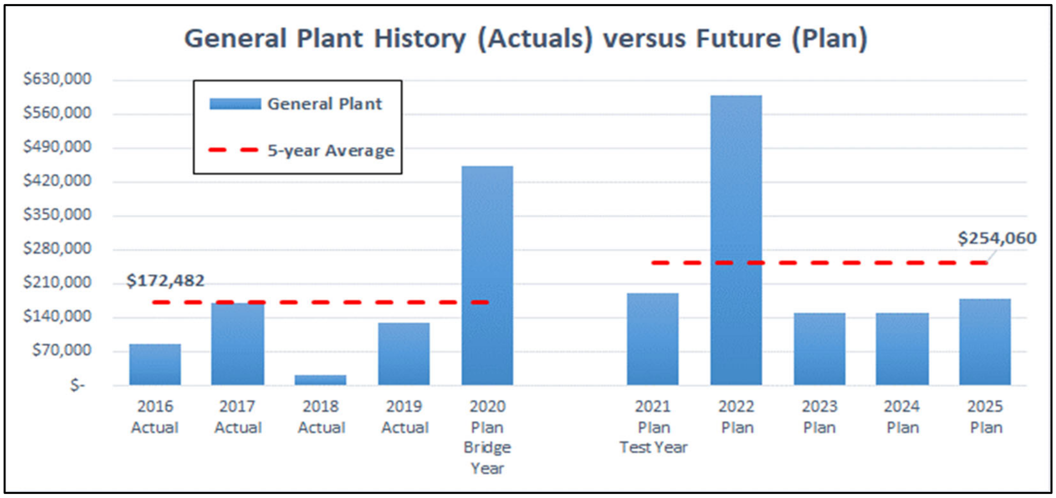
Figure XX - System Service – Historic Actuals versus Planned – Net CapEx

Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Plan Bridge Year	2021 Plan Test Year	2022 Plan	2023 Plan	2024 Plan	2025 Plan
System Service	$ 24,434	$ 10,954	$ 54,500	$ -	$ -	$26,500	$18,500	$21,000	$81,500	$14,000
Cap Contribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Capital	**$ 24,434**	**$ 10,954**	**$ 54,500**	**$ -**	**$ -**	**$ 26,500**	**$ 18,500**	**$ 21,000**	**$ 81,500**	**$ 14,000**

General Plant

The chart below illustrates how much VSU spent (Actuals) on General Plant over the historic period of 2016-2020 compared to the LDC's forecasted CapEx plan for this investment category:

Figure XX - General Plant – Historic Actuals versus Planned CapEx



General Plant expenditure includes investment in IT, IT cyber-security, shop tools, fleet vehicle replacement and building renovations. In years 2020 and 2022, VSU are a replacing bucket truck in each year. In 2019, VSU deferred the replacement of a 2004 model year RBD bucket truck until 2022 as this vehicle is in good condition with minimal usage.

The figure above illustrates the 5-year plan for General Plant expenditures being above the historical spending and activities in this category. The primary reason for this yearly average increase is VSU's continued investment in:

- IT cyber-security to meet the Ontario Cybersecurity Framework[7] to provide the OEB with information pertaining to their Cybersecurity and Privacy Maturity implementations. VSU has embarked on a 5-year plan to meet all requirements and has made substantial headway in the first 3 covenants of the framework: Identify, Protect and Detect. The path forward will consist first of further refinement of the multitude of investments and procedures and will then move to the other two covenants of the framework, Respond and Recover. As these final two areas of the framework incorporate and leverage all prior investments, the solid base achieved to date will provide an exceptionally effective foundation to further enhance cyber-security and Privacy mandates and will ensure a successful completion to the Ontario cyber-security Framework within the targeted timeframe.
- IT Customer Information System (CIS) upgrade scheduled for 2022. This project includes CIS software upgrades for billing, customer service records, paperless work-orders and data/web-presentment. It is envisioned that new technology can be embraced to improve the experience provided to customers in accessing their electricity bill and viewing consumption history on-line with ease and securely.

The table below illustrates VSU's Net Capital Expenditures, both historically and for the proposed planning period. As per previous years, VSU is not anticipating any Capital Contributions for General Plant projects in the forecast plan period of 2021-2025:

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[7] "Ontario Cyber-Security Framework" (version 1.0), December 6, 2017

Figure XX - System Service – Historic Actuals versus Planned – Net CapEx

Category	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Plan Bridge Year	2021 Plan Test Year	2022 Plan	2023 Plan	2024 Plan	2025 Plan
General Plant	$ 86,356	$170,195	$ 22,304	$130,557	$ 453,000	$190,500	$598,050	$151,450	$150,800	$179,500
Cap Contribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Capital	**$ 86,356**	**$170,195**	**$ 22,304**	**$130,557**	**$ 453,000**	**$190,500**	**$598,050**	**$151,450**	**$150,800**	**$179,500**

4.3 Comparison of Historical Actual Expenditures versus Historical Planned

The table below illustrates VUS's 5-year historical period CapEx plan and Actual CapEx costs segmented by the OEB investment categories:

Figure XX - VSU's Historic Period Plan and Actual Costs

	Historical Period - Plan and Actual														
	2016			2017			2018			2019			2020		
Category	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
System Access	$ 55,000	$ 38,722	-29.6%	$ 240,000	$ 77,353	-67.8%	$ 240,000	$ 140,741	-41.4%	$240,000	$ 63,630	-73.5%	$ 60,000	$ 24,571	-59.0%
System Renewal	$ 90,000	$ 113,170	25.7%	$ 390,000	$ 454,353	16.5%	$1,932,000	$2,012,186	4.2%	$290,000	$475,616	64.0%	$450,000	$ 67,051	-85.1%
System Service	$1,373,217	$1,307,297	-4.8%	$ -	$ 10,954		$ -	$ 54,500		$ -	$ 5,180		$ -	$ 1,377	
General Plant	$ 75,694	$ 86,356	14.1%	$ 138,670	$ 170,195	22.7%	$ 24,470	$ 22,304	-8.9%	$421,850	$130,557	-69.1%	$453,000	$188,911	-58.3%
Total CapEx	**$1,593,911**	**$1,545,545**	**-3.0%**	**$ 768,670**	**$ 712,855**	**-7.3%**	**$2,196,470**	**$2,229,731**	**1.5%**	**$951,850**	**$674,983**	**-29.1%**	**$963,000**	**$281,910**	**-70.7%**

** "2020 Actual" correct as at May 31st 2020.*

Variances between Historical Actual Costs versus Planned by OEB Category.

a) System Access

Residential & Small Business meter replacement project: In VSU's 2015 DSP, the LDC included a budget for "Residential & Small Business meter replacement project" under Service Access. The utility was planning to replace its Smart meters over a 3-year period of 2017 to 2019 with an annual budget of $180,000 as meters were approaching their 10-year meter seal life as recognized by Measurement Canada. At the time of filing its's 2015 DSP, it was unknown whether sampling would produce results that would allow for the meters to be "re-sealed" for an additional six years. Therefore, VSU include the estimate for full replacement of meters.

Smart Meters have an asset life, according to Kinectrics Inc., of 15 years yet only 10 years according to Measurement Canada. By having the meters tested and resealed, VSU decided it would be in the interest of its rate-payers not to replace the meters but to have them re-verified and resealed. Also, VSU revised the OEB investment for this project from "System Access" to "System Renewal" as the assets' life, according to Measurement Canada, had been extended (renewed). The table below summarizes the variances between Plan and Actual as well as category change:

Figure XX - 2017 Meter Replacement Project Amended to Meter Reverification

<table>
<tr><th>Project</th><th>Category</th><th>Plan</th><th>Actual</th><th>Variance</th></tr>
<tr><td>Residential & Small Business meter replacement project</td><td>System Access</td><td>$180,000</td><td></td><td rowspan="2">($122,604)</td></tr>
<tr><td>Residential & Small Business meters sample tested, re-verified and resealed</td><td>System Renewal</td><td></td><td>$57,396</td></tr>
</table>

As noted in 2017, VSU elected to sample test, reverify and reseal Smart Meters rather than replace and revised the OEB investment for this project from "System Access" to "System

Renewal". The table below summarizes the variances between 2018 Plan and Actual as well as category change:

Figure XX - 2018 Meter Replacement Project Amended to Meter Reverification

Project	Category	Plan	Actual	Variance
Residential & Small Business meter replacement project	System Access	$180,000		($60,958)
Residential & Small Business meters sample tested, re-verified and resealed	System Renewal		$119,042	

b) System Renewal

Pole-line Rebuild – Queen Street West

In 2017, the Township planned to resurface the road and sidewalk of Queen Street West in Mount Forest. The assets located in this area were circa 1975 and approaching the end of their life. The existing Class 6 poles were replaced with Class 3 poles to meet current construction and safety standards. The porcelain insulators were replaced with safer polymer type insulators. During this period there was discussion regarding a potential new develop at the far west end of Queen St W. It was decided that the far end rebuild would be deferred until a further investigation of the potential development was completed.

Figure 1 - 2017 Pole-line Line Project Variance Analysis

Project	Category	Plan	Actual	Variance
Pole-line Rebuild – Queen Street West	System Renewal	$190,000	$101,715	($88,285)

Pole Line Rear to Front Conversion- Holstein Line Rebuild.

The Holstein Line Rebuild was a 2018 system renewal project included in VSU's 2015 DSP. The project was intended to facilitate the backyard to conversion of several residential customers to front lot feeds with the pole line supplying electricity to the rear fed lots and travels through a field with no roadway. The project was estimated to cost $70,000; however the project did not proceed because:

i. During 2018, VSU replaced an aged substation (MS4) with a new substation. The Operations team were more involved in the project than initially planned, for instance helping with the tear-down of the old substation.
ii. Looking through outage records, there have been three power outages in this area over the period 2012 to 2017.
iii. There have been no complaints or requests to move the service from the several residential customers that live in this area.
iv. The rear lot pole line remains accessible although not ideal the project was deemed cost prohibitive.

Due to the above factors, the project did not happen; and at the time of preparing VSU's capital plan for 2021-2025, this project has not been included. Because this project did not start, this contributed to the 2017 variance:

Figure XX - 2018 Pole-line Line Project Variance Analysis

Project	Category	Plan	Actual	Variance
Pole-line Rebuild – Holstein Rear-Lot Conversion	System Renewal	$70,000	$0	($70,000)

c) **System Service**

New 44 kV Feeder

In 2016, with assistance from Hydro One Networks Inc. (HONI), VSU installed a new 44kV feeder to the Town of Mount Forest to address capacity and reliability concerns. This capital investment project was included in VSU's 2015 Distribution System Plan with an estimated total project cost, as at February 2016) of $1,373,217 which included the following items:

Figure XX - 2016 2nd Line 44kV Feeder Estimates versus Actuals

Project Component	Estimated Cost	Actual Cost	Variance
Hydro One work involving construction of 11 km line expansion to the south end of Mount Forest	$881,156	$838,434	($42,722)
Hydro One's capacity study of the current feeder to Mount Forest	$32,061	$32,061	$0
New Primary Metering Equipment	$80,000	$87,639	$7,639
VSU pole-line work to connect new feeder to LDC's existing system	$380,000	$350,293	($29,707)
Total	**$1,373,217**	**$1,308,427**	**($64,790)**

The 2nd line 44kV feeder project was completed in 2016, energized in December 2016 and under budget as illustrated above. In May 2016, VSU entered into a Capital Cost Recovery Agreement (CCRA) with Hydro One based upon a 50/50 split of HONI's total cost for construction of 11 km line expansion to the south end of Mount Forest – the CCRA amount was $838,434 (before HST) which was below HONI's quote of $881,156 (before HST, quote as at February 2016).

Safety Protection and Control Equipment

In 2018, VSU invested in safety protection and control equipment that was unplanned, i.e. not included in the LDC's 2015 DSP. Consequently, this caused an overage in spending in category System Service of:

Figure XX - 2018 Safety Protection and Control Equipment

Project	Category	Plan	Actual	Variance
Replacement of 4kV Gang Operated Switches replacing Single Solid Blade Switches.	System Service	$0	$42,347	$42,347
Delta Meter Upgrades. The Electrical Safety Authority (ESA) issued a bulletin for "Delta" services with "Wye" transformers and no neutral connections. VSU identified 10 locations in our service area upgrades were needed to connect the neutral or install a neutral conductor. Nine of the ten were completed in 2018 (the tenth location was completed in 2019).	System Service	$0	$6,654	$6,654
Replacement of 44kV Solid Blade Isolation Switch on load side of PME.	System Service	$0	$5,500	$5,500
Total		**$0**	**$54,500**	**$54,500**

d) General Plant

Bucket Truck Replacement Deferred

In VSU's 2015 DSP, the LDC planned to replace a bucket truck in 2019 with a budget amount of $250,000. During the quotation process it was deemed that delivery would not be until 2020 with a cost closer to $325,000. VSU also had a planned replacement of the Radial Boom Derrick "RBD" in 2020 with a budget of $345,000. VSU decided it would obtain new quotes for the RBD and defer its replacement since the vehicle remains in acceptable condition.

The purchase of the bucket truck is to be completed in 2020 and therefore VSU underspent by $250,000 in the "General Plant" investment category:

Figure XX - 2019 Fleet vehicle Replacement - Deferred

Project	Category	Plan	Actual	Variance
Replacement of 2007 Bucket Truck – deferred to 2020	General Plant	$250,000	$0	($250,000)

VSU has included the replacement of the 2004 RBD truck in the capital expenditure program for the 5 year period 2021 to 2025.

4.4 Justifying Capital Expenditures

This section provides the necessary data, information, and analyses to support the Capital Expenditure levels proposed by VSU in this DSP. In managing its' distribution system assets, VSU core objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. VSU is committed to providing our customers with an economical, safe, reliable supply of electricity and enabling our community to be energy efficient. These objectives have been met through the application of thorough and sound planning, prudent and justified budgeting while implementing the documented capital, and operating plans. VSU's system capacity or capability has not experienced any issues with connection of new services or microFIT or a small FIT project to its system and does not expect any issues within the current 5-year plan.

[The justification for capital projects below are only samples. Similar justification should be provided for material capital investments]

4.4.1 Project: Pole Line Re-Build

Project Purpose:
This program represents the most significant portion of VSU's asset management objectives. The purpose of the "Pole-Line Rebuild Project" program is to achieve a sustainable replacement rate that results in proactive replacement of many poles near end of life, but prior to failure. The result is a balance between the cost of the replacement program and relatively larger costs, reliability impacts, and safety concerns associated with reactive replacement of these assets. The resulting annual "levelized" replacement rates allows for efficient use of internal resources.

Project Scope:
Pole line rebuild projects focus on replacing areas where assets located along the route circa vintage 1975-1980 and approaching the end of their life. The existing Class 6 poles will be replaced with Class 3 poles to meet current construction and safety standards. In addition, the porcelain insulators will be replaced with safer polymer type insulators.

Project Spending:
Start date, in-service date and expenditure timing over the planning horizon will be within the annual fiscal year. The annual spending profile during the forecast period for this work is:

Figure XX - Forecasted CapEx: Pole Line Rebuild Projects

Program	Category	5-year Capital Investment Program Plan				
		2021	**2022**	**2023**	**2024**	**2025**
Pole Line Rebuild Projects	System Renewal	$185,000	$185,000	$185,000	$185,000	$185,000

Capital Contributions:
VSU assumes no capital contributions for this project.

Assets Replaced:
The target replacement rate for the Line Rebuild program is approximately 48 poles per year. The program's annual replacement target is based on the number, age and overall condition of in-service poles. Annual program costs are based on rolling annual average cost from 2016-2019, approximately $3,500 per pole.

The chart below shows the number of poles replaced under Pole-Line Replacement projects for the historical years of 2016 to 2020 and forecast period 2021 to 2025.

Figure XX - Pole Line Rebuild Projects – Number of Poles

Year	#of poles	Avg $ per pole	Total Cost
2016	28	$3,521	$98,588
2017	32	$3,568	$114,176
2018	18	$3,608	$64,944
2019	39	$3,622	$141,258
2020	33	$3,680	$121,440
2021	36	$3,864	$139,104
2022	37	$4,057	$150,116
2023	35	$4,260	$149,102
2024	34	$4,473	$152,084
2025	34	$4,697	$159,688

The above table incudes the cost of the pole, labour and truck expense; it does not include the cost to replace and install other assets (such as transformers).

Project Priority:
The health condition and age profile of VSU's current pole population is currently at a point where the occurrence of pole failure (excluding causes such as tree contact, vandalism and motor vehicle accidents) is infrequent in relation to the overall number of forced outages.

Standards:
VSU is a member of the Utilities Standard Form (USF) and, like many other LDCs in the province, uses USF engineering standards which satisfies the requirements applicable for this type of work.

Asset Ownership:
VSU will 100% own and maintain all poles installed.

Alternatives Considered:
VSU has considered alternatives that involve increasing or decreasing the annual replacement target associated with this program. Based on the number of overall pole changes anticipated over the next five years through all capital projects and programs, VSU expects little change in the number of near-end of life poles upon completion of the 5-year plan. Over time, increasing the annual pole replacement targets would effectively decrease the average in-service pole age and the average age of poles being replaced. In VSU's opinion, the LDC does not believe this to be warranted based on the historical performance and failure rates of these assets.

Other information:
Below is a list of pole line projects with approx. costs for years 2021 and 2022.

Figure XX - Pole Line Rebuild Projects

2021 Poleline Rebuild Projects	
Project Description	**Est. Cost**
Smith St. (Frederick to Conestoga)	$ 61,000
Ayshire	$ 60,000
Eliza (Leonard to Carrol)	$ 34,000
Misc Road Crossing Poles	$ 30,000

2022 Poleline Rebuild Projects	
Project Description	**Est. Cost**
Holstein	$ 52,000
Wellington Rs 109	$ 26,000
Smith St. (Preston to Agrison)	$ 60,500
Oxford	$ 24,000
Misc Road Crossing Poles	$ 22,500

4.4.2 Project: Computer – Hardware and Software

Project Purpose:
This budget item includes the annual replacement of workstations, IT network equipment and miscellaneous hardware on regular cycles, with relatively consistent year-over-year replacements. The organization's practice is to replace IT hardware assets every five years at the end of their standard manufacturer warranty period.

Project Scope:
This budget item includes:
- In 2021, VSU will be replacing its virtual servers (budget amount of $63,000). The current virtual servers were installed in 2016 and included a 5-year manufacturer's warranty and 24/7 service package.
- In 2022, the utility will be upgrading its' Customer Information System (CIS) software used for billing, account management and collections. This upgrade will also include a software upgrade to the LDC's current web-presentment solution. Web-presentment is a customer-driven solution enabling customers to access their account and energy usage through an on-line portal.

Project Spending:
Start date, in-service date and expenditure timing over the planning horizon will be within the annual fiscal year. The annual spending profile during the forecast period for this work is:

Figure XX - Forecasted CapEx: SCADA

Program	Category	5-year Capital Investment Program Plan				
		2021	2022	2023	2024	2025
IT - Hardware & Software	General Plant	$111,400	$160,550	$98,950	$41,300	$122,000

Capital Contributions:
VSU assumes no capital contributions for this project.

Assets Replaced:
Continued replacement of IT assets on predictable cycles will result in the most efficient use of internal resources, the lowest program costs in the long term and an enhanced level of cybersecurity together with privacy protocols.

Project Priority:
This investment is a high priority within the General Plant category as the LDC's IT infrastructure underpins the critical office functions of the business, namely customer service, billing and account collections.

Standards:
Continued investment in replacing IT hardware and software as well as leveraging on all prior investments will provide an exceptionally effective foundation to further enhance cyber-security and privacy mandates contained within the Ontario cyber-security Framework within the targeted timeframe. This investment will also address some of the findings from third-party external penetration testing audits conducted in 2017 and 2019.

Asset Ownership:
All IT hardware and software assets will be owned by VSU and will be funded through its capital program, that is the recovery of annual deprecation in its' rate-base to pay for the materials and labour to install the necessary equipment.

Alternatives Considered:
VSU has considered alternatives that involve increasing or decreasing the annual replacement target associated with this program. However, without timely and prudent spending as well as installing latest releases and patches, the risk of system failure and cyber-security breaches threats may occur.
All IT networks, software or hardware are unique to VSU and not shared with other parties.

Other information:
In VSU's opinion, this prudent investment is for the consistent replacement of IT hardware and software on predictable cycles that align with warranty coverage and expected useful lives of assets. Deviation from this approach could result in failures outside of warranty periods, increase risk of system failures, unpredictable annual costs, and cybersecurity vulnerabilities. Furthermore, the utility needs to keep pace with new technology including its web-presentment self-serve solutions to its customers whilst managing data privacy.

IT hardware/software projects fall under the OEB categorization of General Plant.

APPENDIX B

VERY SMALL UTILITIES WORKING GROUP REPORT

EB-2023-0229

FEBRUARY 28, 2024

Background:	There are two load forecasting methods noted in the filing requirements. A Multivariate Regression model and a Normalized Average Use per Customer model (NAC). Very Small Utilities identified that the Multivariate Regression model requires a lot of time and resources but the NAC model would require less time and could be completed internally. To assist very small utilities with completing a NAC model in house, a sample is provided.
Circumstances where NAC may be appropriate:	1) For Customer Classes With Non-Weather Sensitive Loads • No recent or anticipated customer reclassification. • Historical class average use per customer reasonably constant (or variations explainable by one-time events) • No new customers forecasted (or treated separately if anticipated load for new customers known) • No anticipated events that could lead to changes in existing customer use • For classes with only a few customers - confirmation from those customers that historic loads are representative of future anticipated loads. 2) For Customer Classes With Weather Sensitive Loads • Minimal customer growth • No anticipated events that could lead to changes in customer use (or alternatively these changes are addressed separately). • No known historic events (apart from weather) that impacted historic use per customer over the period used to calculate NAC. • Demonstration that historic variations in annual per customer use are linked to variations in weather. • Average HDD and CDD over period used to calculate NAC similar to definition of “weather normal”
Notes:	The number of years used in the sample NAC model is meant to be a sample. A very small utility should assess the number of years to use for the NAC model that best represents their situation.

Load Forecast using Normalized Average Consumption (NAC) method

Table A

Customer Rate Class	OEB-Approved 2016	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast Bridge Yr	2021 Forecast Yest Year
	kWh (Metered without Loss)							
Residential	27,408,200	24,960,131	24,523,576	23,863,110	25,345,905	25,253,896	25,348,334	25,524,068
GS <50 kW	12,494,682	12,033,955	11,967,606	11,410,391	11,582,140	11,138,172	11,566,273	11,539,259
GS 50-999 kW	14,065,279	20,081,441	19,893,743	19,029,613	18,305,429	18,739,880	19,094,120	18,993,178
GS 1,000-4,999 kW	50,613,209	47,530,355	45,496,516	45,750,527	43,913,956	42,766,148	42,766,148	42,766,148
Unmetered Scattered Load	3,024	5,184	6,816	6,801	6,801	6,288	6,288	6,288
Sentinel Lighting	23,128	24,839	22,057	19,673	19,673	19,673	19,673	19,673
Street Lighting	725,392	720,792	723,427	697,359	691,015	650,270	650,270	650,270
Total	**105,332,914**	**105,356,697**	**102,633,741**	**100,777,475**	**99,864,919**	**98,574,327**	**99,451,106**	**99,498,884**
							OK	OK

2015 - 2019: Actual kWh metered (without Loss)
Forecast years: from Table G

Table B

Customer Rate Class	OEB-Approved 2016	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast Bridge Yr	2021 Forecast Yest Year
	kW							
Residential								
GS <50 kW								
GS 50-999 kW	55,775	55,778	55,436	53,405	52,915	51,685	52,662	52,383
GS 1,000-4,999 kW	99,709	99,567	96,818	98,592	98,025	96,230	96,230	96,230
Unmetered Scattered Load								
Sentinel Lighting	69	70	61	55	55	55	55	55
Street Lighting	1,984	1,984	1,984	1,920	1,902	1,810	1,810	1,810
Total	**157,537**	**157,399**	**154,299**	**153,972**	**152,896**	**149,780**	**150,757**	**150,478**
							OK	OK

2015 - 2019: Actual kW
Forecast years: from Table H

Table C

Customer Rate Class	OEB-Approved 2016	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast Bridge Yr	2021 Forecast Yest Year	kW:kWh ratio to use for 2020 Forecast Bridge Yr	kW:kWh ratio to use for 2020 Forecast Test Yr
	Ratios									
Residential										
GS <50 kW										
GS 50-999 kW	0.0040	0.0028	0.0028	0.0028	0.0029	0.0028	0.0028	0.0028	0.0028	0.0028
GS 1,000-4,999 kW	0.0020	0.0021	0.0021	0.0022	0.0022	0.0023	0.0023	0.0023	0.0023	0.0023
Unmetered Scattered Load										
Sentinel Lighting	0.0030	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
Street Lighting	0.0027	0.0028	0.0027	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028

Table B / Table A

Table D

Customer Rate Class	OEB-Approved 2016	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast Bridge Yr	2021 Forecast Yest Year
	Customers / Connections							
Residential	3,251	3,212	3,219	3,246	3,279	3,302	3,325	3,348
GS <50 kW	476	474	469	473	470	470	469	468
GS 50-999 kW	38	36	36	35	34	35	35	35
GS 1,000-4,999 kW	5	5	5	5	5	5	5	5
Unmetered Scattered Load	1	1	2	2	2	2	2	2
Sentinel Lighting	29	27	24	23	23	23	23	23
Street Lighting	905	905	907	908	908	908	908	908
Total	**4,705**	**4,660**	**4,662**	**4,692**	**4,721**	**4,745**	**4,767**	**4,789**

Customer / Connections Growth Rate

2016	2017	2018	2019	Geomean	Substituted
1.002	1.008	1.010	1.007	1.007	
0.989	1.007	0.995	1.000	0.998	
0.995	0.977	0.978	1.029	0.995	
1.000	1.000	1.000	1.000	1.000	
1.583	1.263	1.167	1.000	1.236	1.000
0.906	0.962	0.996	1.000	0.965	1.000
1.002	1.001	1.000	1.000	1.001	1.000

2015 - 2019: Actual # of accounts / connections

Forecast years:
Determine Year-over Year change (growth rate)
Calculate Geomean
Multiply Geomean by latest Actual Year = Bridge Year
Multiply Geomean by Bridge Year = Test Year
Geomean looks odd - then substitute

Table E

Customer Rate Class	OEB-Approved 2016	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast (Avg of 2015-2019)	2021 Forecast (Avg of 2016-2020)
	Annual Average Usage per Customer (kWh without Loss)							
Residential	8,431	7,771	7,618	7,352	7,731	7,648	7,624	7,624
GS <50 kW	26,249	25,366	25,499	24,136	24,634	23,698	24,667	24,667
GS 50-999 kW	370,139	561,719	559,075	547,615	538,395	535,425	548,446	548,446
GS 1,000-4,999 kW	10,122,642	9,506,071	9,099,303	9,150,105	8,782,791	8,553,230	9,018,300	9,018,300
Unmetered Scattered Load	3,024	5,184	4,305	3,401	2,915	2,695	3,700	3,700
Sentinel Lighting	798	937	919	852	855	855	884	884
Street Lighting	802	796	798	768	761	716	768	768

Table A / Table D
Forecast years (2020 & 2021) are based on an average of Actuals of 2015-2019

Table F

Customer Rate Class		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
		Non-Weather Sensitive kWh (metered kWh without Loss)												
GS 1,000-4,999 kW	kWh	3,713,836	3,328,094	3,702,190	3,599,075	3,737,964	3,496,914	3,535,484	3,895,410	3,701,547	3,751,540	3,388,848	2,915,246	**42,766,148**
	kW	7,896	7,693	7,822	8,046	8,163	7,972	8,137	8,283	8,312	8,226	7,889	7,792	**96,230**
Unmetered Scattered Load	kWh	557	521	521	521	521	521	521	521	521	521	521	521	**6,288**
Sentinel Lighting	kWh	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	**19,673**
	kW	5	5	5	5	5	5	5	5	5	5	5	5	**55**
Street Lighting	kWh	74,921	64,343	63,867	53,487	49,129	40,413	42,988	47,901	52,299	61,411	48,220	51,290	**650,270**
	kW	159	159	159	159	159	159	159	159	159	159	115	110	**1,810**

Non-weather sensitive = customer class not affected by hot or cold weather
Use latest monthly Actuals to

Table G

Customer Rate Class	Weather Sensitive	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast Bridge Yr	2021 Forecast Yest Year	
		Weather Normalized kWh							
Residential	Yes	24,960,131	24,523,576	23,863,110	25,345,905	25,253,896	25,348,334	25,524,068	*Weather-Sensitive*
GS <50 kW	Yes	12,033,955	11,967,606	11,410,391	11,582,140	11,138,172	11,566,273	11,539,259	*Weather-Sensitive*
GS 50-999 kW	Yes	20,081,441	19,893,743	19,029,613	18,305,429	18,739,880	19,094,120	18,993,178	*Weather-Sensitive*
GS 1,000-4,999 kW	No	47,530,355	45,496,516	45,750,527	43,913,956	42,766,148	42,766,148	42,766,148	*Not Weather-Sensitive*
Unmetered Scattered Load	No	5,184	6,816	6,801	6,801	6,288	6,288	6,288	*Not Weather-Sensitive*
Sentinel Lighting	No	24,839	22,057	19,673	19,673	19,673	19,673	19,673	*Not Weather-Sensitive*
Street Lighting	No	720,792	723,427	697,359	691,015	650,270	650,270	650,270	*Not Weather-Sensitive*
Total		**105,356,697**	**102,633,741**	**100,777,475**	**99,864,919**	**98,574,327**	**99,451,106**	**99,498,884**	

Forecast years calculated by:

a) Weather Sensitive customers: 5-year average use per customer x number of accounts/connections
[Table E Test Year Forecast x Table D]

b) Non-weather sensitive customers: Most Recent Actual kWh
[use Table F Totals]

Table H

Customer Rate Class	Weather Sensitive	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast Bridge Yr	2021 Forecast Yest Year	
		Weather Normalized kW							
Residential	Yes								*Weather-Sensitive*
GS <50 kW	Yes								*Weather-Sensitive*
GS 50-999 kW	Yes	55,778	55,436	53,405	52,915	51,685	52,662	52,383	*Weather-Sensitive*
GS 1,000-4,999 kW	No	99,567	96,818	98,592	98,025	96,230	96,230	96,230	*Not Weather-Sensitive*
Unmetered Scattered Load	No								*Not Weather-Sensitive*
Sentinel Lighting	No	70	61	55	55	55	55	55	*Not Weather-Sensitive*
Street Lighting	No	1,984	1,984	1,920	1,902	1,810	1,810	1,810	*Not Weather-Sensitive*
Total		**157,399**	**154,299**	**153,972**	**152,896**	**149,780**	**150,757**	**150,478**	

Forecast years calculated by:

a) Weather Sensitive customers: Ratio x Weather Normalized kWh
[Table C Test Year Forecast x Table G]

b) Non-weather sensitive customers: Most Recent Actual kW
[use Table F Totals]

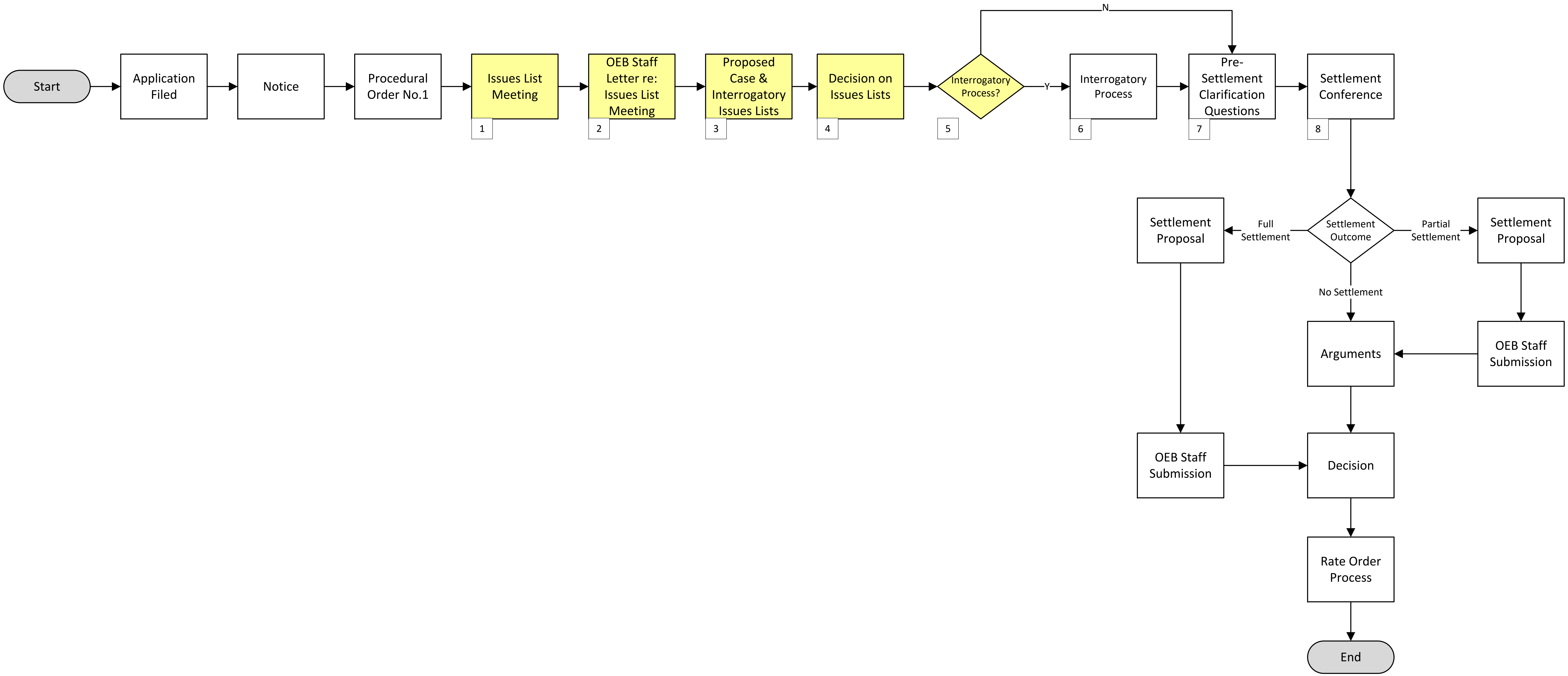
APPENDIX C

VERY SMALL UTILITIES WORKING GROUP REPORT

EB-2023-0229

FEBRUARY 28, 2024

Very Small Utilities Cost of Service Process Map	Process Owner: Nancy Marconi	Approved By: Approved Date:	Created By:	Version No: 1 Version Date: 01/03/24	Page 1 of 2



Note: Based on a typical Cost of Service process for a very small utility

Legend

Start, End

Process Step

New Step

Process Decision

Explanation #

Explanations

1 **Issues List Meeting**

A meeting will take place between the applicant, the intervenor(s) and OEB staff to identify the key issues in the case, clarify information and distill the issues of concern in the proceeding.

The goal of the meeting is to reduce the number of interrogatories required or propose to eliminate the need for a formal Interrogatory process if a consensus is made between parties.

1. During the meeting, the parties will outline the scope of the proceeding by settling on a proposed Case Issues List. The Case Issues List will form the scope of the Settlement/ Decision processes.

2. Parties will also settle on a proposed Interrogatories Issues List, which will form the scope of the Interrogatory process. The Interrogatory Issues List should be a subset of the Case Issues List and should contain none, all, or a portion of the Case Issues List. If parties cannot settle on a Interrogatory Issues List, the Case Issues List will be used in its place.

3. In addition, OEB staff will present a list of errors found in the initial application for the applicant to address. This process will replace the status quo error-checking process.

The meeting will be virtual and will span 1 business day. The meeting itself will not be made public or saved (i.e., no transcripts or recordings).

2 **OEB Staff Letter RE: Issues List Meeting**

OEB staff will file a letter with the OEB outlining the results of the Issues List Meeting, including a list of additional evidence that the applicant has agreed to file (including error-checking results), if any.

The evidence may be filed in advance of, during, or after the Settlement Conference, as agreed to by the parties.

The letter may also include a proposal for alternative Settlement Conference dates, if needed.

3 **Proposed Case & Interrogatory Issues List**

Alongside the OEB Staff Letter RE: Issues List Meeting, OEB staff should submit to the OEB the proposed Case Issues List and the proposed Interrogatory Issues List as agreed to by the parties. The letter may also propose alternative settlement conference dates depending on the outcome of the Issues Lists.

OEB staff should provide adequate reasoning to the OEB as to why it believes the proposed Issues Lists are reasonable.

4 **Decision on Issues Lists**

The OEB will issue a decision on the Case Issues List and the Interrogatory Issues List prior to the start of the Interrogatory process.

The OEB will also issue a decision on any proposed alternative case schedule included within the OEB Staff Letter.

5 **Interrogatory Process?**

Yes - If the OEB finds that there are issues required as part of the Interrogatory Issues List, the parties may proceed to the Interrogatory process.

No - If the OEB finds that there no issues required as part of the Interrogatory Issues List, the parties may proceed to the Settlement process.

6 **Interrogatory Process**

The Interrogatory process should require less questioning from intervenors and OEB staff compared to the status quo process given the responses to questions during the 1-day Issues List Meeting and a potentially reduced Interrogatory Issues List compared to the Case Issues List.

7 **Pre-Settlement Clarification Questions**

Prior to the Settlement Conference, parties may informally ask the applicant questions to clarify any remaining matters.

The goal of the Pre-Settlement Clarification Questions is to clarify the record for the purposes of coming to a settlement.

Parties may wish to have the responses to the Pre-Settlement Clarification Questions put on the record.

8 **Settlement Conference**

Parties will attempt to settle on the issues identified in the OEB-approved Case Issues List.

The conference will take place over 2 days instead of 3 to offset the 1 day required for the Issues List Meeting.

Unless there are objections from the parties, OEB staff will facilitate the Settlement Conference. This shall be outlined in PO#1.