Q. Further to the response to PUB-NP-018:

a) Travel costs are forecast to increase significantly in the 2024-2026 period over the 2023 test year forecast. The response in part c) states the increase is due to a return to normal levels after the COVID-19 pandemic and inflationary increases. What specific action is Newfoundland Power taking to keep these costs as low as possible? In the response include the type of travel included (whether for operating maintenance, conferences, training etc.) and how Newfoundland Power employs remote work as a way to reduce costs.

b) Education and training costs are forecast to increase in the 2024-2026 period over the 2023 test year forecast. The response in part e) states that this category of cost was limited in 2023 due to the COVID-19 pandemic and is forecast to return to normal and also reflects changing workforce demographics. What specific action is Newfoundland Power taking to keep these costs as low as possible? In the response include an explanation of how Newfoundland Power utilizes on-line training.

c) Changes in other company fees are said in part f) to be in part due to increases in cybersecurity costs. Please provide details on the costs associated with cybersecurity in the period 2023-2026 and explain the reasons for the increases in this category of cost.

d) Part f) i) of the response refers to an increase of $.5 million related to information technology. Please explain the reason for this increase.

e) Part f) ii) refers to an increase of $1 million in costs for regulatory proceedings, consultants for information technology and asset management and audit fees. Please state the increase for each and explain the reasons for the increase in each.

f) Part g) states that vegetation management increased significantly in 2023 compared to the forecast and is forecast to increase again in 2025 and 2026. Please explain why the 2023 actual cost was so much higher than the forecast and the increases forecast for 2024 to 2026. Also provide the costs incurred for vegetation management each year for the period 2013 to 2023.

g) Does Newfoundland Power have a strategy or policy for its vegetation management program referred to in part g)? If yes, please provide it. When did Newfoundland Power last review its policy or approach to vegetation management? Please explain if and how its approach to vegetation management is consistent with good utility practice.

h) Please quantify the reasons for changes in vegetation management costs over the period 2017 to 2026 between the amount of vegetation management completed/planned and the cost per unit of vegetation management (i.e., inflationary costs).

i) Computing equipment and software cost increases over the 2023-2026 period are said in part h) to relate to the introduction of new technology and replacement of existing technology. What new technologies are being introduced and what are being retired that are increasing costs and what is the increased cost of each new technology?

j) Using the same breakdown of costs as in the Table please provide the test year forecast, the actual results and the variance between test year and actuals for the three general rate applications prior to the 2022 General Rate Application.

A. a) Travel includes operating costs for airfare, hotel accommodations, vehicle rentals, relocation, and other travel-related costs for operations, and training and development. While annual travel costs may fluctuate depending on operational needs,[1] the Company manages and minimizes these costs through various means and established policies.[2]

Operational travel costs are managed through the strategic location of employees throughout the Company's service territory. Further, and as outlined in the Company's *Travel Expenses Policy,* Newfoundland Power is required to provide employees with necessary transportation for completing work assignments. This includes, where possible, the use of Company fleet vehicles as opposed to rental vehicles when travelling within the Company's service territory.[3] Employees may also use their personal vehicle at the request of the Company for travel within its service territory, which reduces costs in comparison to those associated with renting a vehicle. Where possible, the Company uses virtual meetings to reduce the need for employee travel.

The Company also uses remote and hybrid meetings, where possible, to reduce travel costs associated with Company-led initiatives, such as education and training programs. Employees also regularly attend meetings and conferences virtually, thereby avoiding travel costs. Certain in-person meeting and conference attendance, however, is required based on business and employee development needs.

The Company has an agreement with a third-party travel management company to reduce travel costs. Special rates are built into the travel management system, which employees are expected to use, for air travel, hotel accommodations and vehicle rentals. For example, the online booking system includes limits for employees for airfares, which assist in reducing travel costs. In accordance with the *Travel Expenses Policy,* employees are expected to take all reasonable measures to minimize the cost of air travel, including taking advantage of lower cost fares.

Finally, the Company employs guidelines for accommodations and meal allowances for employees when travelling to manage travel costs. The use of guidelines establishes maximums for accommodations and meals, ensuring travel costs remain within an acceptable threshold.

b) Newfoundland Power uses a range of actions to keep education and training costs as low as possible and continuously seeks opportunities to further reduce costs, while ensuring education and training align with workforce needs and changing workforce demographics.[4] This primarily includes the following actions.

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1 See Newfoundland Power's *2022/2023 General Rate Application*, response to Request for Information NLH-NP-003, Attachment A, page 43 of 60. In 2010, travel expenditures increased by $108,000 resulting from Hurricane Igor and the need to move crews throughout the province based on the location of needed work.

2 This includes the Company's *Travel Expenses Policy*, as well as its Collective Agreements.

3 This is subject to the availability of fleet vehicles and operational requirements.

4 For example, at the end of 2023, 31% of permanent employees had less than five years of experience at the Company compared to 9% at the end of 2020.

(i) *Utilizing free training programs where possible*. The Company avails of free training programs and webinars offered by external organizations and industry associations where possible. For example, in 2023 and 2024 Newfoundland Power availed of free training and education sessions offered by techNL and Women in Resource Development Corporation on Diversity, Equity, Inclusion and Belonging.

(ii) *Offering virtual education and training sessions*. Newfoundland Power uses virtual and hybrid meeting options for training sessions where possible to reduce associated travel costs. This has reduced travel costs associated with training sessions that were previously held as in-person only. For example, the Company modified its new employee orientation training, which had historically been in-person only, to offer a virtual attendance option.

(iii) *Availing of internal program facilitators to reduce costs*. The Company uses a 'Train the Trainer' model to utilize internal education and training program facilitators where possible to reduce costs associated with external program facilitators. For example, the Company is providing mental health training to all employees and people managers in 2024. The Company opted to have internal session facilitators trained by the Mental Health Commission of Canada, who will in turn facilitate the program to Company employees.

c) A cybersecurity breach could have significant impacts for Newfoundland Power and its customers.[5] Cyber attacks are increasing in the electricity sector[6] and have occurred locally.[7] As such, it is critical for the Company to manage cyber risk.

Table 1 outlines other company fees associated with cybersecurity for 2023 to 2026.

Table 1:
Other Company Fees for Cybersecurity
2023 to 2026 Forecast
($000s)

2023A	2024F	2025F	2026F
145	302	307	312

Other company fees related to cybersecurity include fees for annual penetration testing, incident response support and risk management assessments. The cost increase in 2024 reflects the introduction of the Security Information and Event

[5] For example, IBM Security provided in a 2023 report that the average cost of a data breach reached an all-time high in 2023 of US$4.45 Million. See the response to Request for Information PUB-NP-023, footnote 8.

[6] See International Energy Agency. *Cybersecurity – is the power system lagging behind?* Retrieved on March 30, 2024 from https://www.iea.org/commentaries/cybersecurity-is-the-power-system-lagging-behind.

[7] Ransomware attacks were made on Newfoundland and Labrador's health-care system in 2021 and Memorial University's Grenfell campus in 2023. See CBC News. *Ransomware was behind cyberattack on MUN's Grenfell campus, confirms president.* Retrieved on March 30, 2024 from https://www.cbc.ca/news/canada/newfoundland-labrador/cyberattack-memorial-university-1.7084427.

Management ("SIEM") service. Through the SIEM service, a third-party will monitor the Company's systems 24/7 to reduce cybersecurity risk.

d) The $0.5 million increase in other company fees related to information systems is due to the SIEM service, as referenced in part c) of this response, and for support and maintenance of the Company's new Customer Care and Billing System.

e) The increase of $1 million in other company fees in the 2023 forecast compared to the 2023 test year primarily reflects the following.

(i) $490,000 related to the Company's regulatory proceedings. This relates to the *2025/2026 General Rate Application*, as well as increased costs associated with the Company's capital budget application and other regulatory filings.

(ii) $280,000 related to information technology, including $170,000 associated with asset management. A consultant was engaged to support the Company in assessing a new asset management system, including defining the business and technology requirements, providing technology recommendations, and supporting the alignment of the Company's technology and asset management roadmaps.

(iii) $170,000 in audit-related fees. The Company engaged a third party to provide assurance over the internal controls associated with the Customer Information System implementation, resulting in a $145,000 increase in audit-related other company fees.

(iv) $155,000 in engineering consultant costs. This primarily includes penstock inspection and condition assessments, and an asset management maturity assessment.

The increases above were partially offset by lower other company fees associated with anticipated Newfoundland and Labrador Hydro regulatory proceedings, which were delayed.

f) Newfoundland Power's forecast vegetation management costs in 2023 were $3,259,000 compared to the 2023 test year amount of $2,441,000. This represents an increase of $818,000, or approximately 34%.[8] The increase is primarily due to additional distribution and transmission vegetation management activity, as well as inflationary cost increases.

[8] $818,000 / $2,441,000 = 34%.

Vegetation Management Requirements at Newfoundland Power

Newfoundland Power's electrical system includes approximately 9,500 kilometres of distribution line and 2,100 of transmission line.[9] These lines are primarily overhead construction and therefore exposed to the elements.[10] Operating costs related to vegetation management are the result of three main drivers: (i) planned tree trimming and brush clearing work identified as part of distribution and transmission inspections;[11] (ii) customer requests for tree trimming near power lines;[12] and (iii) in response to unplanned customer outages caused by trees.

Planned tree trimming and brush clearing requirements that are completed as part of the Company's inspection program have increased compared to prior years.

Table 2 shows the average number of work orders completed in the three years from 2018 to 2020, compared to the three years from 2021 to 2023.

Table 2:
Planned Vegetation Work Orders Completed[13]

2018-2020 Average	2021-2023 Average	Increase (%)
400	578	45

On average, 400 work orders were completed annually between 2018 and 2020 as compared to an average of 578 between 2021 and 2023.[14] This represents an increase of approximately 45%.

The Company also completes tree trimming near power lines resulting from customer requests. This ensures the work is completed in a safe manner, as cutting or trimming trees near energized power lines is hazardous and should be completed by qualified and trained personnel.

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9 Approximately 70% of annual vegetation operating costs are related to the distribution system. For example, $2.3 million of the Company's total vegetation management operating costs of $3.3 million in 2023 were related to the distribution system.

10 Approximately 97% of Newfoundland Power's distribution system is overhead construction. The Company's transmission system includes 2,100 kilometres of transmission line, which is over 99% overhead construction.

11 Newfoundland Power completes identifies planned vegetation management work as part of its distribution line inspections, which are completed on a seven-year cycle, and as a drive-by inspection once in between, as well as during transmission line inspections, which are completed annually.

12 The Company receives over 1,000 tree trimming requests from customers each year.

13 Vegetation work orders are recorded in the Company's asset management system. Work requirements can vary by work order. For example, one work order may represent a single tree to be removed from a line, or it may represent brush clearing to be completed across multiple spans of line, requiring multiple days to complete.

14 The 2023 test year forecast amount was prepared in 2021 as part of the Company's *2022/2023 General Rate Application*, and reflected the work volumes for planned tree trimming over the 2018 to 2020 period.

Table 3 shows the amount of customer requested tree trimming work completed in the three years from 2018 to 2020, compared to the three years from 2021 to 2023.

Table 3:
Customer Tree Trimming Requests Completed

2018-2020 Average	2021-2023 Average	Increase (%)
1,589	1,770	11

On average, 1,589 work orders were completed annually between 2018 and 2020, as compared to an average of 1,770 between 2021 and 2023.[15] This represents an increase of approximately 11%.

In addition to planned work resulting from inspections and customer requests, operating costs related to vegetation management are also driven by unplanned customer outages caused by trees. This is reflected in outage minutes related to tree contacts and indicate broader vegetation conditions across the Company's service territory.

Table 4 provides the percentage of outage minutes related to tree contacts over the 2020 to 2023 period.[16]

Table 4:
Percentage of Outage Minutes – Tree Contacts
2020 to 2023

2020	2021	2022	2023
16%	17%	19%	21%

The percentage of outage minutes related to tree contacts has increased steadily over the 2020 to 2023 timeframe.[17] While the Company does not consider this trending to be alarming, it does reaffirm that a continued focus on vegetation management is required to control vegetation in the Company's service territory.[18]

Finally, the Company's operating environment is an important consideration for vegetation management activities.[19] Wind events cause trees to come into contact

[15] The 2023 test year forecast amount was prepared in 2021 as part of the Company's *2022/2023 General Rate Application*, and reflected the work volumes for customer driven requests over the 2018 to 2020 period.
[16] Under normal operating conditions.
[17] Tree contacts are the second leading cause of outage minutes for Newfoundland Power's customers behind equipment failures.
[18] Electricity Canada provides that customer-related outages due to tree contacts on the distribution network average one in five in Canada. See Electricity Canada. *Vegetation Management*. Retrieved on March 28, 2024 from https://www.electricity.ca/knowledge-centre/outages/reliability/vegetation-management/.
[19] For a fulsome discussion on the Company's operating environment, see Newfoundland Power's *2025/2026 General Rate Application, Volume 1: Application, Company Evidence and Exhibits, Section 3: Finance,* pages 3-37 to 3-39.

with electricity lines. Compared to other electric utilities, Newfoundland Power's service territory is subject to some of the most severe wind and ice conditions for populated regions of Canada.[20] Changing climate conditions can also pose challenges to vegetation management. Beyond increasing high-wind events, Newfoundland and Labrador is expected to experience a significant increase in total growing degree days,[21] and has experienced more wildfires consistent with the rest of Canada.[22]

Newfoundland Power's increase in vegetation management costs in 2023 compared to the 2023 test year, as well as its 2025 and 2026 test year forecast, are reflective of increased work requirements related to planned and customer driven work requirements experienced over the last three years. In Newfoundland Power's view, based on the above, the requirement for increased levels of vegetation management is reasonable.

Comparison to Atlantic Canadian Utilities

The Company also completed a scan of vegetation management operating costs across Atlantic Canada.

Table 5 summarizes the findings of that scan.[23]

Table 5:
Atlantic Canada Comparison
Vegetation Management Operating Costs

Utility	Indicated Vegetation Operating Costs ($millions)	Approximate Distribution Lines (kilometres)	Approximate Transmission Lines (kilometres)
Newfoundland Power	3.4	9,500	2,100
Maritime Electric	4.0[24]	5,881	727
Nova Scotia Power	4.2 to 11.5[25]	26,500	5,300
NB Power	8.2[26]	21,717	6,868

[20] Wind speeds in excess of 100 km/hr occur routinely in Newfoundland Power's service territory. For example, over the 2014 to 2021 timeframe, wind speeds in excess of 100 km/hr averaged 50 days per year.

[21] Growing degree days is a measure of energy availability for plant growth. See Dr. Joel Finnis and Dr. Joseph Daraio, Memorial University of Newfoundland, *Projected Impacts of Climate Change for the Province of Newfoundland and Labrador: 2018 Update*, page 36. Retrieved March 28, 2024 from: https://www.turnbackthetide.ca/tools-and-resources/whatsnew/2018/Final_Report_2018.pdf.

[22] By May 2023, Newfoundland and Labrador experienced 53 wildfires, which represented an increase over the previous year. Similarly, Canada experienced a record-breaking number of wildfires in 2023.

[23] Information for each utility was gathered from publicly available information, such as its most recent general rate application, annual reports, sustainability reports and websites.

[24] Anticipated spend for 2025.

[25] Over the 2010 to 2021 timeframe, Nova Scotia Power spent an average of approximately $15 million on vegetation management. Of this average amount, approximately $7.5 million was an operating expense. Annual operating expenses related to vegetation management ranged from $4.2 million to $11.5 million.

[26] Anticipated spend for 2024/2025.

The scan provides that Newfoundland Power's current level of vegetation management operating costs is consistent with the other utilities in Atlantic Canada.[27] More broadly, vegetation management is one of the largest ongoing operational expenses for utilities and viewed as critical to utility operations.[28]

Vegetation Management Costs

Table 6 provides the Company's vegetation management operating costs for 2013 to 2026 forecast.

Table 6:
Vegetation Management Operating Costs
2013 to 2026 Forecast
($000s)

2013	1,993
2014	1,789
2015	1,766
2016	1,820
2017	2,099
2018	1,692
2019	2,042
2020	2,306
2021	2,524
2022	3,230
2023	3,328
2024F	3,323
2025F	3,377
2026F	3,432

g) Newfoundland Power's vegetation management practices are outlined in its *Distribution Inspection and Maintenance Practices* and *Transmission Inspection and Maintenance Practices* policies, which are provided in Attachments A and B, respectively.

Newfoundland Power's asset management functions were reviewed by The Liberty Consulting Group ("Liberty") in 2014.[29] Liberty provided the following associated with Newfoundland Power's asset management practices:

[27] Newfoundland Power can also provide that in its *2024 Annual Review of Rates Application*, FortisBC provided that it spent $0.4 million more than the formula amount related to vegetation management. FortisBC provided that it expects that the higher spending will continue as it is critical to ensure system reliability and safety.

[28] See Electricity Canada. *Vegetation Management.* Retrieved on March 28, 2024 from https://www.electricity.ca/knowledge-centre/outages/reliability/vegetation-management/.

[29] See *The Liberty Consulting Group, Supply Issues and Power Outages Review Island Interconnected System, Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.,* December 17, 2014, page ES-2.

"The program, organization, and staffing of Newfoundland Power's asset management functions are sound. The Company uses an effective combination of periodic inspection and maintenance programs and capital rebuild and modernization projects. ***Vegetation management practices also conform to good utility practices****." (emphasis added).*

h) Newfoundland Power does not track its vegetation management costs in a manner that would allow for an accurate breakdown of cost per unit of vegetation and contractor price changes.[30] However, the Company can provide that its vegetation price changes are generally reflective of its overall non-labour cost inflation experienced since 2017.

Table 7 provides a comparison of Newfoundland Power's 2017 and 2026 forecast vegetation management operating costs on both a nominal and inflation-adjusted basis.[31]

Table 7:
Vegetation Management Operating Costs
2017 and 2026 Forecast
($000s)

	2017	**2026F**
Nominal	2,099	3,432
Inflation-Adjusted	2,550	3,259

On a nominal basis, vegetation management costs increased by $1.3 million from 2017 to 2026 forecast. On an inflation-adjusted basis, vegetation management costs increased by $0.7 million over that timeframe, which can be attributed to additional vegetation management requirements.

As provided in part f) to this response, Newfoundland Power's continued vegetation management at current levels is required over the forecast period and is reasonable in comparison to the other Atlantic Canadian utilities.

i) See Attachment A to the response to Request for Information PUB-NP-140, which provides a listing of the Company's software, its business requirement (new, replacing an existing software, or is ongoing) and the cost changes from 2022 to the 2026 forecast.

j) Attachment C provides test year operating cost forecasts, actuals and variances for the three general rate applications prior to, and including, Newfoundland Power's *2022/2023 General Rate Application*.

[30] Contracts for vegetation management are for various types of vegetation management (for example, brush clearing in hectares, and tree trimming in hours for distribution and transmission) and multiple contractors are used across the Company's service territory.

[31] Stated in 2023 dollars using the GDP Deflator for Canada.

Distribution Inspection and Maintenance Practices

DISTRIBUTION INSPECTION AND MAINTENANCE PRACTICES

Approved By: Byron Chubbs, P. Eng.
Approved Date: March 4, 2013
Revised By: M. R. Murphy, P. Eng.
Revision Date: December 11, 2017

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DISTRIBUTION INSPECTION AND MAINTENANCE PRACTICES

Policy Statement

Scheduled inspection and maintenance procedures shall be undertaken on all distribution lines. The inspection and repair process is intended to ensure safe and reliable operation. Regional Directors are ultimately responsible to ensure that distribution line inspection and maintenance activities are completed in accordance with this policy in their respective regions.

Public & Employee Safety

The Company owns and operates in excess of 9,000 km of distribution line in both rural and urban environments. Distribution line corridors may be used as trail-ways for snowmobile operators, ATV operators, skiers, hikers and others and are also regularly used by employees to carry out maintenance activities. Distribution lines and distribution rights-of-ways must be inspected and maintained in a manner that assures the safety of the public.

Regular inspections of distribution lines and timely repair of identified deficiencies will minimize risk to the public and employees. Those conducting distribution line inspections have the responsibility to inspect lines thoroughly with a keen focus on identifying potential public and employee safety hazards. Regional Directors, Managers of Operations and Supervisors responsible for maintenance have the shared responsibility to ensure that inspections are completed and any identified deficiencies and hazards are corrected in accordance with this policy.

Inspection Type and Frequency

All overhead primary distribution lines are required to have a minimum of one detailed ground inspection every seven years. However, Managers of Area Operations have the discretion to have more frequent inspections done if time and manpower allow.

Distribution Vegetation Management requires that distribution lines are inspected, on average, every three and a half years for brush clearing and tree trimming. These inspections will be completed as part of the distribution line inspection every seven years, and as a drive-by inspection once in between.

Pad mount transformers are to be inspected annually. These inspections should be completed at the same time as the detailed ground inspection or vegetation inspection if they are required during the same year.

Inspector Qualifications

To inspect Newfoundland Power distribution lines, an inspector must have the following minimum qualifications:

- Minimum 3 years of experience in the electrical utility industry in the operations or engineering area.
- Familiarity with the operation, maintenance and construction of utility lines.
- Familiarity with the use and operation of ATV's and snowmobiles.
- Basic understanding of the electrical and mechanical nature of utility lines.

Distribution Asset Management System

All distribution line preventative maintenance and inspections as well as deficiency identification and corrective maintenance activities shall be recorded in the Company's computerized asset management system known as Avantis.

The Information Systems and Regional Operations groups are responsible for administering Avantis and for training users. Maintenance Supervisors, Schedulers, Planners, Line Supervisors, Managers, and others within the Regional Operations group may have access to this system.

In addition to the software package, there are a number of business processes that detail the responsibilities and handoffs for each step in the asset management system. They can be found on Webster under the Regional Operations department in the Asset Management folder.

Distribution Line Inspections (7 Year Cycle)

Guidelines for detailed ground inspections of distribution lines and the associated record-keeping procedures are as follows:

- Personnel performing inspections shall use the necessary equipment to assist in the evaluation of distribution line components. For example, a hand held computer, binoculars, plumb bob, hammer, core sampler, screwdriver, crescent wrench, and digital camera may be needed.
- Inspection personnel shall assign a Maintenance Priority for each deficiency identified. This priority shall establish when corrective action is required (more information on assigning priority is given in Appendix A - Deficiency Reference Tables).
- Reasonable judgment is required in determining if something should be recorded as a deficiency. Each structure must be analyzed from the perspectives of Public Safety,

Employee Safety, Reliability and Environment to determine if action is warranted. For example;

- It is not the intent to bring all existing plant up to the current construction standards. Simply because a structure is not built to the latest construction standard does not mean it is deficient.

- It is not the intent to record every minor deficiency. For example, if the inspector determines that a minor chip in a pole does not undermine the strength of the pole and poses no danger to public or employee safety, reliability or environment, then it should not be entered into the maintenance system as a deficiency.

Distribution Vegetation Management Inspections (7 Year Cycle)

A distribution line shall have a vegetation inspection completed twice every seven years. This inspection shall be completed as part of the distribution line ground inspection every seven years, and as a drive by inspection once in between. The inspection should be documented on Hand Held Devices.

A vegetation deficiency can be one of two types. (1) A brush clearing deficiency which requires the entire width of the right of way to be cleared. A single brush clearing deficiency may cover an area several kilometers long. (2) A tree trimming deficiency in which a single tree or several trees at the same location are contacting or are in danger of contacting the line and will need to be trimmed. Each tree or small group of trees at the same location is considered a single deficiency.

To assign a priority to the vegetation deficiency, the inspector must take into consideration the details of the vegetation growth, as well as the following:

- Public and employee safety
- The physical location of the line (populated or remote area, near existing roadways or cross-country, etc.)
- The anticipated growth rate (depending on the type of vegetation)

Padmount Transformer Inspections (Annual)

Padmount transformers shall be inspected at least once per year and maintenance to the transformer completed in a timely manner. The inspection should be documented on Hand Held Devices.

This is a visual inspection only.

Appropriate Personal Protective Equipment is to be worn at all times.

Distribution Line Component Inspection Guidelines

Distribution line inspections require evaluation of the following components. For each component there are guidelines to follow during inspections. These guidelines do not cover all possible deficiencies that may exist on each component, and reasonable judgement must be used by the Planner in identifying and prioritizing deficiencies.

Structures

Wood Poles:

During each distribution line inspection, all wood poles require a detailed visual inspection. Depending on the results of the visual inspection a sounding test may be performed. If the visual inspection and/or the sounding test indicate a problem, a core-sampling test may be performed to aid in the evaluation of the pole.

- Inspect and determine condition of pole at ground line and above for rotting, deterioration, splitting, cracks, breaks, burns, woodpecker holes, insect infestation and plumbness.
- Ensure pole is properly backfilled and not undermined.
- Where applicable, inspect condition of crib timber. Ensure crib is properly rock filled.
- Check structure for plumbness or any degree of misalignment.
- Check for structure number tags.
- Ensure that pole grounds are installed on all poles with transformers on them. Ensure that it is rigidly supported, it has not been cut and a ground guard is present and secured

Steel Towers:

- Inspect tower for damaged or missing members. Check member connections for loose or missing nuts and bolts. Check members for buckling.
- Inspect tower for corrosion. Check tower for plumb and any degree of misalignment. Check for structure number tags.
- Inspect backfill conditions around tower footings and legs. Check footing for deterioration. Inspect foundation for surface cracks or splitting. Check that reinforcing is not exposed. Inspect anchor bolts for cracks, rusting or missing anchor nuts.
- Check tower for missing or damaged Danger Signs. Ensure that signs are clearly visible. Check condition of anti-climbing barriers. Anti-climbing barriers and warning signs should be installed on all steel towers. It is a significant public safety issue for barriers or signs to be missing and the deficiency should be classified as a TD1.

Hardware

Cross Arms and Braces:

- Inspect crossarms for rot, splits, cracks and twisting that may cause the conductor to fall to the ground. Also, inspect for burn marks.
- Check that cross arms or braces aren't loose, broken or hanging.

Platforms:

- Check that platform brace isn't loose, broken or hanging.
- Check that platform deck isn't failing or sagging.

Anchors and Guys:

- Inspect guys and pre-formed grips for wear, breaks, slackness and corrosion.
- Ensure guy guards are secure and installed on every guy wire. A missing guy guard is a significant public safety issue and should be classified as high priority.
- Inspect anchor rod and backfill conditions. Check for anchor rod damage. Ensure anchor is not undermined or pulling. Ensure that anchor eye is above ground level.
- Check that all guys are either insulated or effectively grounded to neutral/ground wire.
- Any anchor rods with no guy attached should be identified as a high priority work order if the guy is required or cut off by the planner on-site if the guy is not required.

Insulators

Polymer Type:

- Inspect for broken, split, misaligned, flashed or defective insulators
- Check non dead-end insulators for uplift
- Check that stand off brackets aren't twisted, delaminated or broken

Porcelain Type:

- Inspect for broken, cracked, chipped, misaligned, flashed or defective insulators.
- Check non dead-end insulators for uplift.
- Check that stand off brackets aren't twisted, delaminated or broken
- 2-piece and 8080 insulators should be identified for removal. If they are damaged they should be given a high priority.

Conductor

Primary and Neutral Conductors:

- Check for excessive sag that could result in phases slapping together. Also check for too much tension that could result in vibration induced problems such as broken ties, insulators, or conductor breaks.
- Inspect conductors for safe clearances from buildings, roads, ground, and other power/communication lines.
- Inspect conductor for broken or frayed strands, burn marks, foreign objects.
- Inspect splices for abnormal condition.
- Inspect dead-end assemblies for any abnormal condition.
- Where required, inspect for damaged or missing conductor warning markers.
- Check that tie wires or clamps are not loose or broken.
- Automatic splices, or quick sleeves, should be identified for removal.

Stirrups/Leads/Primary Connections:

- Check hardware for any visible deficiency that may result in conductor falling to the ground.
- Check for broken or corroded conductor near connections.
- Check leads for excessive length.
- Visually inspect conductor around hot line clamps for corrosion and broken strands.

Underground Cables/Conduit/Guards:

- Inspect cable and pothead for damage.
- Check for bad connections.
- Ensure guards are present and secured and grounded as required.

Primary Devices

Pole Mounted Transformers:

- Inspect transformers for rust and leaks. Transformers that are leaking or are rusted to the point that a leak appears imminent must be replaced immediately.
- Ensure that all transformers have PCB identification tags installed (Yellow, Green or White). Particularly, transformers in Protected Public Water Supply Areas contain a green or white PCB identification tag. If no tag is installed then the transformer oil

must be tested. Ensure to note transformer number, civic address, and addresses of customers fed off of transformers to be PCB tested.

- Check for cracked or broken bushings.

- Check for proper tank ground. Each tank is to have a minimum of two independent paths to ground.

- Check that secondary leads aren't rubbing against bottom rim of tank.

- Check for blown fuses.

- Check that animal/bird guards are properly installed and aren't broken or hanging off.

- 25 kVA and 50 kVA unpainted stainless steel ABB transformers without reinforcing brackets shall be identified to have reinforcing brackets installed.

- Transformers with pole mounting brackets showing signs of bending or splitting shall be replaced immediately. Transformers with known design flaws but are not currently exhibiting signs of failure shall be noted for future support bracket installation. Ensure to note if the transformer is located in a sensitive location such as school yard or other high traffic area.

Metering Tanks:

- Inspect tanks for rust and leaks.

- Check for cracked or broken bushings.

- Check for proper tank ground.

- Check that secondary leads aren't rubbing against bottom rim of tank.

Lightning Arrestors:

- Check that Lightning Arrestors (LA) are installed. LA's should be installed on distribution transformers if there is any other reason to climb or otherwise work the pole above ground level. In addition LA's should be installed on all underground dip poles, and on all equipment such as down line reclosers, regulators, and sectionalizers.

- Inspect for broken, cracked, chipped, misaligned, flashed or defective insulators.

- Checked that lightning arrestor has not failed.

Capacitors:

- Inspect tanks for rust and leaks.

- Check for cracked or broken bushings.

- Check for proper tank ground.

- Check for blown fuses.

Switches

Cutouts:

- Ensure disconnects are correctly labeled.
- Check that Current Limiting Fuses (CLF) are installed as required. This includes;
    - All cutouts where fault levels are greater than 10,000 Amps.
    - On cutouts protecting distribution transformers where fault levels are greater than 5,000 Amps and less than 10,000 Amps.
    - On cutouts protecting distribution transformers that are located in proximity to areas where the public is known to gather (e.g. near bus stops, near play ground equipment, etc.) where fault levels are greater than 3,000 Amps but less than 5,000 Amps.
- All porcelain cutouts, except on individual transformers, shall be identified for replacement.

In-Line Switches:

- Ensure disconnects are correctly labeled.
- Ensure blades are in fully open or closed position.
- Check insulators for deterioration or damage.

Gang Operated Switches:

- Ensure disconnects are correctly labeled.
- Check switch for signs of tampering. Check locks and locking mechanism are intact and secure. Gang-operated switches in areas readily accessible to the public are required to be double-locked. Inspect switch handle, pipe, etc. for damage and proper alignment. Inspect all ground connections for tightness, corrosion and damage.
- Check that the switch blades are in the fully open or the fully closed position as per its normal configuration.
- Inspect Insulators for damage.
- Ensure ground mat has not been disturbed. Check for missing or damaged danger signs. Ensure that signs are clearly visible.

Vegetation and Right of Way

To assign a priority to the vegetation deficiency, the inspector must take into consideration the details of the vegetation growth, as well as the following

- Public and employee safety.

- The physical location of the line (populated or remote area, near existing roadways or cross-country, etc.).

- The anticipated growth rate (depending on the type of vegetation).

Brush Clearing:

- Check condition of vegetation growth along right-of-way.

- When recording a brush clearing vegetation deficiency, be sure to record information on the type of brush to be cleared (deciduous or coniferous), the density of brush to be cleared (Light, Medium, Heavy), the average height of the brush, and the start and end points of the section on line requiring brush clearing.

- Check for danger trees that may contact the conductor or trees close to the line that can be easily climbed. Remember that a persons weight on a weak branch could cause it to deflect enough to contact the line.

Tree Trimming:

Public Safety and Reliability are important factors in determining the priority of the danger tree deficiency. When recording a danger tree deficiency, it is important to make the following considerations:

- Whether the tree is in close proximity to the energized high-voltage conductors such that it may make contact. Consider that a branch may swing or bend into the line due to the weight of a climber, wind or buildup of snow or ice.

- Whether the tree is easily accessed from the ground and climbable.

- Whether individuals who are possibly interested in climbing the tree frequently visit the site that the tree occupies.

Encroachments:

- Check for encroachments by foreign structures, unauthorized excavation or fill areas, etc. These should be identified as a deficiency if the Planner judges them to be a public safety hazard.

Distribution Padmount Transformer Inspection Guidelines

Distribution padmount transformer inspections require evaluation of the following components. For each component there are guidelines to follow during inspections. These guidelines do not cover all possible deficiencies that may exist on each component.

Exterior

- Ensure the company number is present and consistent with the Avantis hierarchy

- Check for deficiencies in the door and locking mechanism.

- If there is no danger sticker present, install one.
- Check for signs of oil leaks and severe rusting. Less severe rusting that will not lead to failure within the next year should not be noted as a deficiency.
- Check for proper placement of the padmount transformer on the pad.
- Ensure a snow marker is installed on the unit where required.
- Check for a PCB label. If the label is missing but the PCB content can be found from the nameplate or a test sticker on the interior, apply the appropriate label.
- Check for problems with the foundation, fences or posts and remove any debris from inside. Note any vegetation control required.

Hardware

- Replace any missing bolts and broken locks.
- Check for test caps on the load break elbows.
- Ensure fault indicator is present and reset.

Nameplate

- Verify inclusion and completeness of nameplate information in the handheld.

Bushings

- Ensure the primary and secondary bushings are not damaged.

Connections

- Check condition of all primary and secondary connections. Make note of any visible damage or bonding requirements.

Lightning Arrestors

- Check for lightning arrestors on the primary dip pole.

Typically any transformer removed from service that is greater than 30 years old, requiring painting or testing, should be handed over directly to the waste disposal contractor for scrapping. Units less than 30 years old should be shipped to the Electrical Maintenance Centre for refurbishment if in good condition, and if

- Leaking
- PCB status uncertain
- Involved in an insurance claim

It should also be noted on the work orders that padmounts being scrapped directly from the field should have their nameplates removed and the company number of the padmount written on the back of the nameplate. Nameplates should then be shipped to the EMC.

Also, any units being shipped to the EMC should be tagged with removal details including who removed the padmount from service, where it was previously installed, removal date and reasons why the unit was removed from service.

Communications Plant Inspections - Bell

As part of a distribution line inspection it is required to also inspect any communication equipment belonging to Bell Canada on joint use poles. It is not required to prioritize these deficiencies but anything that in the Planner's judgment is an emergency should be noted and reported as such. Plant belonging to other communication providers are not required to be inspected. Pole and anchor deficiencies in Bell's pole setting areas should follow the existing process for this type of work.

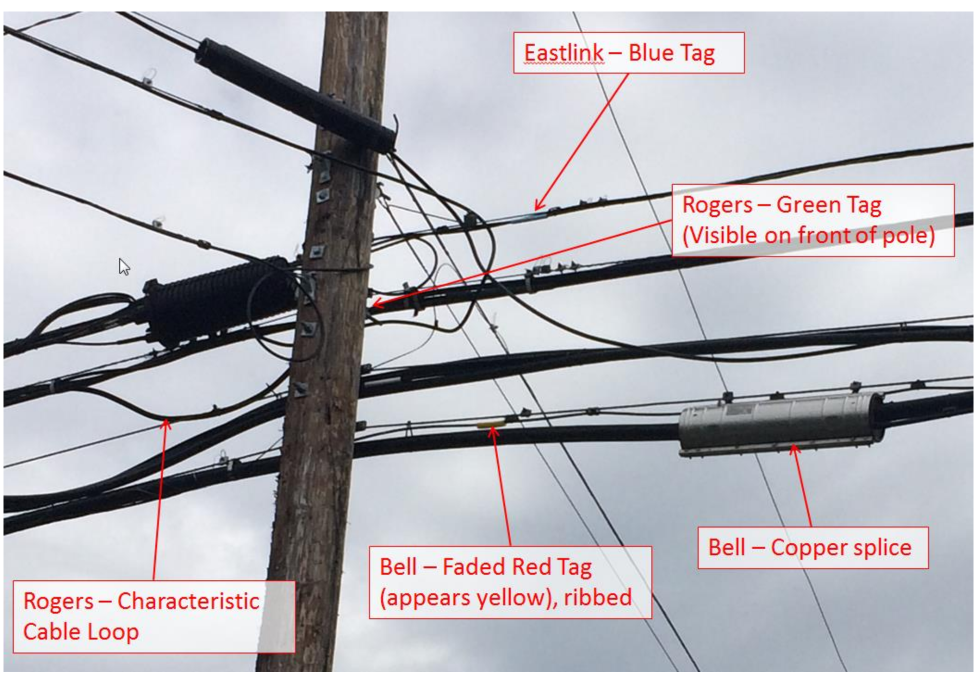
Identification of Bell Equipment

Equipment belonging to different communications companies can be identified by coloured tags present at pole attachments.

Bell – Red tags. These tags tend to fade to orange then yellow over time so care is required to not confuse with Eastlink's longer yellow tags. Bell equipment tags also have a 'ribbed' appearance similar to weeping tile.

Rogers – Green tags. Rogers also has a 'loop' at each pole attachment.

Eastlink – Yellow or blue tags. Eastlink's yellow tags can be distinguished from Bell's faded tags due to their longer length.



Messenger Strand

- Visually Inspect condition of strand for breakage, severe rust, frayed ends.
- Visually inspect for broken or loose lashing wire.
- Note locations for improperly sagged strand / cables requiring re-tensioning
- Note areas of inadequate clearance
- Note areas of inadequate separation from neutral / power space.
- High voltage ground missing / detached

General

- Visually check for issues with splice closures, strand attachments: improperly strapped, loosely hanging, covers open, etc.
- Vertical riser cables / conduit: visually check for improperly strapped, improper duct sealing; general damage
- Housekeeping: cleanup of utility related debris around pole
- Duplicate Poles / removal required
- Outstanding transfers

Additional Planning Details

When recording a deficiency, it is important to collect as much information as possible to assist in planning a repair.

Outage Requirements

- No Outage
- Single Transformer Outage
- Feeder Tap Outage
- Full Feeder Outage
- Multiple Feeder Outage
- Joint Use

Site Considerations

- Environmental
- Near School or Hospital
- High Traffic Area
- Within 15m of PPWSA
- Truck Accessible
- Number and Type of Customers Affected

On Site Repairs

All deficiencies shall be recorded in the Distribution Asset Management System with the exception of minor repairs that can be completed on site. These minor repairs may be completed by the inspector during a distribution line inspection, or by a line crew completing planned repairs.

The following repairs may be completed on site during a distribution line inspection. The inspector shall carry the required materials to complete the repair.

- Replace or reattach a missing guy guard.
- Tighten a loose pre-form connection.
- Replace or reattach a missing ground cover.
- Add staples to an unsecured ground wire or ground cover.
- Replace or reattach a sign or equipment label.

The following repairs may be completed on site during a padmount transformer inspection. The inspector shall carry the required materials to complete the repair.

- Replace missing or broken bolts and locks.
- Install or reset fault indicators as required.
- Install danger stickers.
- Install PCB label if PCB information is available but label is missing.

A line crew that identifies a deficiency while completing a separate job shall report the deficiency to their supervisor. This deficiency will be entered into the Distribution Asset Management System and planned repairs will be completed. However, it is acceptable that minor repairs be completed on site if they can be completed safely and in a short time. A rule of thumb to use is if the repair is simple and can be completed in less than 20-30 minutes, it shall be completed on site and not recorded as a deficiency.

Any on-site repairs completed on Bell equipment is to be noted for billing to Bell.

Maintenance Classifications

All defects identified through the inspection process are given one of the following classifications based on the nature of the abnormal condition. Unless otherwise stated or directed, the response times shall be as follows:

PRIORITY	RESPONSE TIME
Emergency	Immediate
TD1	1 Week
TD2	1 Month
TD4	Next Budget Cycle
TD5	Opportunity Work Only

The shared responsibility for scheduling maintenance rests with the Planner and Line Supervisor.

If the Planner notes a deficiency that is considered to be an Emergency, he shall immediately notify the area Manager.

If a deficiency is noted to be a TD1 or TD2 priority, they will not be included on monthly maintenance schedules. It is the Planner's responsibility to ensure the appropriate personnel, whether Line Supervisors for line work or Maintenance Supervisor for contract maintenance, is aware of the work and of the high priority nature of the work.

A TD1 priority will permit time for formulating a plan of action to correct the deficiency. Planning should begin immediately to ensure corrective action is taken as quickly as possible after the identification of the deficiency.

Regional Managers / Supervisors will ensure corrective maintenance work is completed, in the time frames outlined above, to prevent failure from occurring.

While it is not possible to cover all conditions that a Planner may encounter, the general guidelines found in Appendix A can be used to assist in the classification of defects. In practice, the Planner will assign priority based on his knowledge and experience.

Appendix A- Deficiency Reference Tables

Wood Poles

DEFICIENCY	EMERGENCY	TD1	TD2	TD4	TD5
Damaged	Broken	Serious Horizontal Cracks			
Pole Rot		Rotted to Imminent Failure		Rotted - Failed Core Test	
Woodpecker Holes				Severe Woodpecker Holes	
Unauthorized Attachments					Unauthorized Attachments
Off Vertical	Severe Lean - Failure Imminent			Lean >10°	
Pole Crib	Major Frame Damage - No Longer Supporting Pole			Frame Damaged - Rocks Becoming Loose	
Pole Ground	Grounds Cut or Broken Near Ground Level Repaired by Planner During Inspection			Grounds Cut or Broken Above Ground Level	Ground Cover Missing Staples Missing Ground Rod Exposed No Pole Ground Installed
Backfilling	Large Hole – Public Safety Hazard		Pole Not Supported		

Cross Arms and Braces

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Cross Arm Damaged	Broken - Floating Phase Severely Crooked - Failure Imminent	Broken		Severe Rot or Cracked
Brace Bent, Missing or Hanging			Missing or Hanging	

Platforms

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Brace Damaged			Brace Loose	Severely Bent
Deck Damaged	Imminent Failure		Broken Beam	Deck Sagging

Anchors and Guys

DEFICIENCY	EMERGENCY	TD1	TD2	TD4	TD5
Guard Missing	Replaced by Planner During Inspection				
Preform Rusting			C or E Structure	All Others	
Loose Guy				Loose Guy	
Preform Unravelling			C or E Structure	All Others	
Broken Guy	C or E Structure or Public Safety		All Others		
Broken Rod or Fitting	C or E Structure or Public Safety		All Others		
Backfilling	Large Hole – Public Safety Hazard		Pole Not Supported	Pole Support Uncompromised	
Anchor Buried				Rotting preform	Stable
Ungrounded / Uninsulated	Pole has damaged insulators or damaged porcelain cutout		Rock anchor, undamaged 2-piece or 8080 insulators or porcelain cutout	All other ungrounded or uninsulated guys	

Polymer Type Insulators

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Split/Broken	Broken	Polymer Split/Rod Exposed		Splits, Skirts Missing
Floating	Floating			
Stand-Off Bracket	Broken			

Porcelain Type Insulators

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Cracked/Broken	Broken	Insulator Severely Cracked		Chips or Cracks, Skirts Missing
Floating	Floating			
Stand-Off Bracket	Broken			
2 Piece / 8080 Insulators		Damaged		All Other Locations

Primary Conductor

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Sag	Public Safety Hazard			Could Cause Slapping
Clearances to Buildings/Signs	Exceeds CSA Standards			Above Dwelling Within CSA Standards
Broken Strands	>1/4 Strands Broken		<1/4 Strands Broken Pencilling	1 - 2 Strands Broken Temporary Repairs
Floating	Floating			
Tie Wires or Clamps	Broken			Loose or Unravelling
Missing Line Guards				On Aluminum or Stranded Copper
Warning Markers	Hanging			Becoming Loose or Missing
Quick Sleeves				All Locations

Neutral

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Sag	Public Safety Hazard		Could Cause Slapping	
Clearances to Buildings/Signs	Exceeds CSA Standards			Above Dwelling Within CSA Standards
Broken Strands	>1/4 Strands Broken		<1/4 Strands Broken Pencilling	1 - 2 Strands Broken Temporary Repairs
Floating	Floating			
Warning Markers	Hanging			Loose or Missing
Quick Sleeves				All Locations

Stirrups/Leads/Primary Connections

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Stirrups Missing				
Lead Length Excessive				Could Cause Slapping
Broken Strands		>1/4 Strands Broken on Main Trunk	<1/4 Strands Broken on Main Trunk	<1/4 Strands Broken – Not Main Trunk Temporary Repairs
Pencilling on Solid Leads		Pencilling		

Underground Cables/Conduit/Guards

DEFICIENCY	EMERGENCY	TD1	TD2	TD4	TD5
Guard Loose			Guard Hanging Off		Guard Loose
Guard Missing		High Traffic Pedestrian Area		Low Traffic Area	
Cable Damaged	Cable Severely Damaged/Broken		Jacket Damaged		
Pothead Damaged			Excessive Pitch Leaking		Minor Pitch Leaking
Cracked/Broken Bushing	Broken	Insulator Severely Cracked			Minor or Moderate Chips or Cracks, Skirts Missing

Pole Mounted Transformers

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Tank Ground	Ungrounded	Only 1 Ground		
PCB Label				Missing
Cracked/Broken Bushing		Bushing Completely Broken		Chips or Cracks, Skirts Missing
Leaking/Weeping	Leaking or Weeping			
Rusting	Rust Causing Leaking or Weeping			Severe Rust
Blown Fuse	Blown Fuse			
Mounting Bracket	Bracket split/ Showing signs of failure		Sensitive locations	Design flaw identified but not showing signs of failure

Metering Tanks

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Tank Ground	Ungrounded			
PCB Label Applied				Missing
Cracked/Broken Bushing		Bushing Completely Broken		Chips or Cracks, Skirts Missing
Leaking/Weeping	Leaking or Weeping			
Rusting	Rust Causing Leaking or Weeping			Severe Rust

Lightning Arrestors

<table>
<tr><th>DEFICIENCY</th><th>EMERGENCY</th><th>TD1</th><th>TD2</th><th>TD4</th></tr>
<tr><td>Floating</td><td>Floating</td><td></td><td></td><td></td></tr>
<tr><td>Grounded Incorrectly/Ungrounded</td><td></td><td></td><td></td><td>Grounded Incorrectly/Ungrounded</td></tr>
<tr><td>Insulator Damage</td><td>Broken</td><td colspan="2">Severe Splits or Cracks</td><td>Splits or Cracks, Skirts Missing</td></tr>
<tr><td>Failed</td><td>Failed. No Power to Customer</td><td></td><td></td><td>Failed. Power Still On.</td></tr>
<tr><td>Missing</td><td></td><td></td><td></td><td>Area prone to lightning strikes</td></tr>
</table>

Capacitor Banks

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Tank Ground	Ungrounded			
Leaking/Weeping	Leaking or Weeping			
Blown Fuse	Blown Fuse			
Insulator Damage	Broken	Severe Splits or Cracks		Splits or Cracks, Skirts Missing
Rusting	Rust Causing Leaking or Weeping			Severe Rust

Padmount Transformers

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Snow Marker			Missing	
Rusting	Rust causing leaking or weeping		Severe rust; leak imminent in less than 1 year – replacement required	Surface rust – painting required
PCB Label				Missing
Defective door	Broken off unit		Broken hinge	
Defective lock/missing bolts	Replace on site			
Xfmr moved off pad			Moved	
Incorrect Co. Number			Missing/Incorrect Co. Number	
Vegetation				Vegetation management required
Primary/Secondary bushings		Broken		
Test cap on load break elbows			Missing	
Ground Strap				Broken/Missing
Connections/Terminations	Completely broken		Damaged	

Cutouts

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Switch Damaged	Switch Damaged			
Insulator Damage	Broken	Severe Splits or Cracks		Splits or Cracks, Skirts Missing
Porcelain				At Tie Points, Main Trunk, Large Taps, Major Customers
Label Missing			Label Missing	
Current Limiting Fuse Required				CLF Required

In-Line Switches

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Insulator Damage	Broken	Severe Splits or Cracks		Splits or Cracks, Skirts Missing
Label Missing			Label Missing	

Gang Operated Switches

DEFICIENCY	EMERGENCY	TD1	TD2	TD4
Grounding	Switch Ungrounded No Ground Mat			
Insulator Damage	Broken	Severe Splits or Cracks		Splits or Cracks, Skirts Missing
Label Missing			Label Missing	

Vegetation and Right-of-Way

DEFICIENCY	EMERGENCY	TD1	TD2	TD4	TD5
Tree Trimming	Touching Conductor or Showing Signs of Burning		Within 2ft of Primary Conductor		
Brush Clearing	Touching Conductor or Showing Signs of Burning		Within 2ft of Primary Conductor	Above Neutral but Greater than 2ft from Primary Conductor	
Encroachments					Encroachments

Transmission Inspection and Maintenance Practices

NEWFOUNDLAND POWER
A FORTIS COMPANY

TRANSMISSION INSPECTION AND MAINTENANCE PRACTICES

Approved By: Mike Comerford, P. Eng.
Approved Date: March 4, 2013

Revised By: M.R. Murphy, P. Eng
Revised Date: June 28, 2018

Table of Contents

TRANSMISSION INSPECTION AND MAINTENANCE PRACTICES

Policy Statement

Regularly scheduled inspections and correction of identified deficiencies shall be undertaken on all transmission lines to provide for safe and reliable operation. Regional Directors are responsible to ensure that transmission line inspection and maintenance activities are completed in accordance with this policy. Responsibility for maintaining and revising this policy rests with the Manager responsible for Transmission.

All preventative and corrective maintenance activities shall be recorded in the Company's computerized Transmission Asset Management System (TAMS).

Public and Employee Safety

Newfoundland Power owns and operates in excess of 2,000 km of transmission lines that transverse both rural and urban environments. Transmission line corridors may be used as trailways for snowmobilers, ATV operators, skiers, hikers and others and are also regularly used by employees to carry out inspection and maintenance activities. As well, in urban areas, lines often travel along streets and through residential neighbourhoods. Because transmission line corridors are used by the public and employees, lines and right-of-ways must be inspected and maintained in a safe manner.

Regular inspections of transmission lines and timely correction of identified deficiencies will minimize risk to the public and employees. Transmission line inspectors have the responsibility to inspect lines thoroughly with a keen focus on identifying potential public and employee hazards. Regional Directors, Area and Regional Managers of Operations, and Line-Supervisors have the shared responsibility to ensure that inspections are completed and any identified deficiencies and hazards are corrected in accordance with this policy.

Inspector Qualifications

As a minimum, an inspector must have the following qualifications to complete the Detailed Ground Inspections on Newfoundland Power's transmission lines:

i) Minimum 3 years of experience in the electrical utility industry, in the operations or engineering area.

ii) Familiarity with the operation, maintenance and construction of transmission lines.

iii) Familiarity with the use and operation of off-road vehicles such as ATV's and snowmobiles.

iv) Basic understanding of the electrical and mechanical nature of transmission lines.

v) Successful completion of Newfoundland Power line inspection workshop "Line Inspection Fundamentals".

The above qualifications can be obtained by a combination of on-the-job training, formal education and training as provided by recognized educational institutions, and internal Company training and workshops.

In order to maintain status as a Newfoundland Power line inspector, the inspector must successfully complete in-house line inspector training every three years.

Typically, all inspections will be carried out by the Planner assigned to the respective area.

Transmission Asset Management System (TAMS)

All transmission line preventive maintenance and inspections as well as deficiency identification and corrective maintenance activities shall be recorded in the Company's computerized maintenance management system known as Transmission Asset Management System (TAMS). The inspections and deficiencies are to be recorded in the field, by inspectors on handheld devices. Data from these devices shall be downloaded regularly into the computer system.

The Transmission department is responsible for administering TAMS and information services for training users. Planners, Supervisors, Line Supervisors, Managers, and others within the Transmission group may have access to this system.

Inspection Type and Frequency

All transmission lines are required to have a minimum of one (1) Detailed Ground Inspection per year. More frequent inspections or patrols may be required on some lines depending on their operating performance and as determined by the Area or Regional Manager of Operations.

Generally, Climbing Inspections shall only be performed on transmission structures/lines to:

a) More thoroughly assess concerns with specific components (i.e. insulators, hardware, crossarms) as identified by ground inspections

b) Ensure a newly constructed line meets construction standards (acceptance inspection).

Regularly scheduled Helicopter Patrols are not required under this policy. Special circumstances and operational problems can arise that will warrant a helicopter patrol (i.e. frequent line trips, storm damage, etc). A patrol performed under these conditions shall not substitute for a ground inspection.

Detailed Ground Inspections

During detailed ground inspections of transmission lines, inspectors will inspect all poles, towers, conductors, insulators, crossarms, crossbraces, anchors, guys, deadends, jumpers, sleeves and other hardware, as well as the right-of-way, and identify deficiencies that require correction.

To provide for a thorough inspection of poles, anchors, and guys at the groundline, at least one (1) of every four (4) ground inspections shall be carried out with no snow cover present.

Personnel performing inspections shall use binoculars, plumb bob, hammer, core sampler, screw driver, crescent wrench, digital camera, height measurement meter and all other equipment deemed necessary to assist in the evaluation of transmission line components.

In some cases it will be necessary for inspectors to utilize off-road capable vehicles such as ATVs, snowmobiles, or Argos. When such vehicles are required, additional considerations will be necessary. If the vehicle used is equipped with an enclosed cab, it is required that the vehicle be equipped with an escape hatch operable from both inside and outside the vehicle. Should water bodies need to be crossed, floater survival suits are required equipment as well.

Any line or site specific hazards or details should be identified by the inspectors on a go-forward basis and noted in handheld device. This information should be consulted before beginning any line inspections to confirm any extra requirements that inspectors should be aware of prior to commencing work, and to communicate any site considerations to contractors who may be working on the lines. Any additional details should be identified by the inspectors on a go-forward basis and noted in handheld device.

When working on "Remote" transmission lines, extra safety equipment and precautions are necessary. Inspectors should have in their possession the following items:

- Appropriately stocked survival kit
- GPS device including most recent mapping software
- Personal flotation devices (PFDs) if use of off road vehicles in water is required

- Redundant transportation such as a second ATV, snowmobile, or Argo; to be used in the case of incapacitation of primary mode of transportation
- At least one satellite phone for use in areas with poor cellular coverage

Inspectors are also required to complete and document tailboard discussions on a daily basis, and more often as needed to address changing conditions and newly identified hazards. Ground conditions and communications limitations should be considered as part of the discussion.

Appropriate operations manual procedures must be followed. Relevant procedures include the following:

- OPR112.08 – “Off Road Vehicles”
- OPR112.16 – “Driving Off Road Vehicles”
- OPR101.16 – “Working Alone or in Isolated Locations”
- OPR101.17 – “Traveling and Working in Remote Areas”
- OPR300.01 – “Risk Management/Job Planning”
- OPR300.03 – “Working Alone”
- OPR112.07 – “Travelling Over Wetlands and/or Bogs”
- OPR106.46 – “Power Line De-Energization and Hold-Off Protection”
- OPR106.47 – “Transmission Line Structures with Damaged Insulators”
- OPR106.48 – “Transmission Line Structures with Damaged Equipment or Hardware other than Damaged Insulators”

Results of detailed ground inspections and identified deficiencies shall be recorded in the field on handheld devices. GPS co-ordinates are to be taken in the field for all structures, approved access trails and hazards.

Transmission Line Component Inspection Guidelines

Transmission line ground inspections require evaluation of the following components. For each component there are guidelines to follow during inspections. These guidelines do not cover all possible deficiencies that may exist on each component, and reasonable judgement must be used by the Planner in identifying and prioritizing deficiencies.

a) Wood Poles

Ensure all ‘nameplate’/structure list information such as structure number, type, etc. is recorded and correct. Collect GPS co-ordinate of pole if required.

Inspect and test wood pole(s) to determine condition at and above the groundline as per the following section - Detailed Wood Pole Inspections.

Ensure pole is properly backfilled and not undermined.

Check poles for any vibrations and indications that conductors are vibrating excessively.

Where applicable, inspect condition of crib timbers. Ensure crib is properly rock filled.

Check structure for plumbness or any degree of misalignment.

Check for structure number tags.

Check rock mounts for damage or deterioration.

b) Crossarms and crossbraces

Inspect the wood crossarms/crossbraces for the following:

- Rotting
- Damage due to burning
- Splitting or Cracking
- Any deformation due to twisting or bending

c) Crib

Inspect and test the crib for the following:

- Proper rock filling
- Rotting/damaged timbers
- Missing timbers

d) Steel Pole Structures

Inspect pole for mechanical damage and corrosion.

Check for plumbness.

Check for number tags. Ensure pole is properly backfilled and not undermined.

Check that steel pole climbing pegs are not installed to at least the 4m height location.

Check structure grounding across section joints.

e) Steel Towers

Inspect tower for damaged or missing members.

Check member connections for loose or missing nuts and bolts.

Check members for buckling.

Inspect tower for corrosion

.

Check tower for plumbness and any degree of misalignment.

Check for structure number tags.

Inspect backfill conditions around tower footings and legs. Check footing for deterioration. Check vegetation around footing.

Check anchor bolts for cracks, rusting or missing nuts.

Check tower for missing or damaged Danger Signs. Ensure that signs are clearly visible.

Check condition of anti-climbing barriers. Anti-climbing barriers and warning signs should be installed on all steel towers.

f) Guys

Inspect guys and preformed grips for wear, breaks, slackness, and corrosion.

Ensure guy guards are secure and are installed on every guy wire. Install additional guy guards where deep snow or drifts are encountered or expected to cover existing guy guards.

Ensure guys are grounded where required.

Ensure guy insulators are properly installed

g) Anchors

Inspect anchor rod and backfill conditions.

Check for anchor rod damage or deterioration.

Ensure anchor is not undermined or pulling.

Ensure preformed grip is completely visible and anchor eye is above ground level.

Check for any abandoned anchor rods that are protruding above ground and may pose a hazard.

h) Insulators

Inspect for broken, cracked, chipped, misaligned, or flashed insulators. Check non-deadend insulators for uplift. Check post insulator studs for backing off and looseness.

If suspension insulators are ≥50% damaged the inspector shall stay clear of the structure in question and take pictures from a distance. These deficiencies should be called in to the Transmission/Distribution Maintenance Supervisor immediately, prioritized as Emergency and brought to the attention of the Area Operations Superintendent. The determination may be made at this time to place the line in Hold-Off immediately as per OPR116.02.

i) Hardware

Check hardware for missing nuts, bolts, cotter pins, and loose, worn, bent or corroded hardware.

Check ball link eye bolts for visible wear in the link connection

FleXall-type saddle clamps have been known to wear at the clevis bolt eventually causing conductor damage or failure. Inspect all FleXall type clamps using binoculars or a spotting scope, to determine the amount of visible wear at the clevis bolt and saddle ears.

j) Conductors & Accessories

Inspect conductor sag. All three conductors should appear to have the same sag. Check for excessive sag that could result in phases slapping together.

Inspect conductors for proper clearances from buildings, roads, ground, other power/communication lines. Use height measurement device to determine conductor height above ground where clearance may not be adequate.

Inspect conductor for broken or frayed strands, bird-caging, burn marks, foreign objects.

Inspect deadend assemblies and splices for any abnormal condition.

Inspect vibration dampers and anti-galloping devices for wear and positioning.

Where required, inspect for damaged or missing conductor warning markers.

k) Ground Wires

Inspect condition of overhead ground wire for corrosion and broken strands.

Inspect structure ground wire. Ensure it is rigidly supported and has not been cut, and that ground wire guard is in place.

Check for tightness and corrosion.

l) Group Operated Disconnect Switches

Check locks and locking mechanism are intact and secure. Check switch for signs of tampering. Gang-operated switches in areas readily accessible to the public are required to be double-locked.

Inspect switch handle, pipe, etc. for damage and proper alignment.

Inspect all ground connections for tightness, corrosion and damage.

Ensure switches are properly labeled.

Check switch blades are in fully open or closed position as per its normal configuration.

Inspect insulators for damage.

Ensure ground mat has not been disturbed.

Check for missing or damaged danger signs. Ensure that signs are clearly visible.

Where switch yards exist, check for damage or deterioration of the fence. Also check to ensure gate is closed and locked, that that fence is adequately grounded and danger signs are in good condition. Check vegetation inside yard.

m) In Line Switches

Ensure blades are in fully open or closed position and locked open for normally open switches.

Check insulators for deterioration or damage.

Check whips for damage and proper alignment.

n) Right of Way

To assign a priority to the vegetation deficiency, the inspector must take into consideration the details of the vegetation growth, as well as the following

- Public and employee safety
- The criticality of the line (radial or loop, number and type of customers, load, etc.)
- The physical location of the line (populated or remote area, near existing roadways or cross-country, etc.)
- The anticipated growth rate (depending on the type of vegetation)

Check condition of vegetation growth along right-of-way.

When recording a brush clearing vegetation deficiency, be sure to record information on the type of brush to be cleared (deciduous or coniferous), the density of brush to be cleared (Light, Medium, Heavy), the average height of the brush, and the start and end points of the section on line requiring brush clearing.

Check for danger trees that may contact the conductor or trees close to the line that can be easily climbed.

Check for tree stumps or cut off pole stumps that could pose a hazard for snowmobiles and ATV's.

Check for encroachments by foreign structures, unauthorized excavation or fill areas, etc.

Any clotheslines or other customer owned attachments on transmission line structures should be removed by the Planner during the inspection.

Detailed Wood Pole Inspections and Testing

The following inspection and testing procedures shall be used to determine the integrity of transmission line wood poles.

Visual Inspection

Inspect the condition of the pole from the groundline to the top on all quadrants. The pole shall be examined for the following defects: pole top rot, ground line rot, external decay, rotting, deterioration, splits, checks, cracks, breaks, burns or other fire damage, woodpecker damage, signs of insect infestation, and plumbness

During each transmission line inspection, all wood poles in service shall require a detailed Visual Inspection.

Sounding Test

Using a flat faced hammer, sound the pole surface at regular intervals on all quadrants from the groundline to 2 m above grade. Care should be taken to detect any difference in sound. When the sound does differ, (i.e. hollow sound) it may indicate internal decay and further testing may be required. This test can be used to evaluate any portion of the pole above groundline.

Sounding Tests shall be randomly done on poles in service 35 years or less.

Poles in service more than 35 years require a Sounding Test during each inspection.

Core Sampling Test

This test is performed using an approved core sampling device. By drilling through the centerline of the pole a core sample can be extracted for evaluation. The location of bore holes shall be determined by the sounding test. All bore holes should be plugged with a tight fitting, treated wooden plug. Also, to avoid transfer of decay, the core sampler must be cleaned with an approved fungicide.

If the visual inspection and/or the sounding test indicate a problem, a Core Sampling Test can be performed to aid in the evaluation of the pole.

Deficiency Prioritization and Correction

Where practical, inspectors shall correct deficiencies on site during a transmission line inspection. The inspector shall carry the required materials to complete the repair.

- Replace or reattach a missing guy guard.
- Tighten a loose pre-form connection or slack guy.
- Replace or reattach a missing ground cover.
- Add staples to an unsecured ground wire or ground cover.
- Replace or reattach a sign, equipment/structure label, or lock.

The Planner shall assign a Maintenance Priority for each major deficiency identified during an inspection which will quantify the seriousness of the deficiency and establish when corrective action is required. All non-Emergency deficiencies are to be priority ranked as TD1, TD2 or TD4 and entered into TAMS via a hand held device.

The correction of deficiencies shall be completed in the time frame outlined below:

CLASSIFICATION OF PRIORITY	RESPONSE
Emergency Immediate security of the line is at risk or serious safety hazard exists.	Immediate
TD1 Deficiencies that are a serious hazard or would result in an interruption if not corrected within 7 days.	Within 7 days
TD2 Deficiencies that are a less serious hazard or would result in an interruption if not corrected within 1 month.	Within 1 month
TD4 Deficiencies that are not a safety hazard which should be corrected as part of the capital plan for the following year	In the following capital year

The shared responsibility for scheduling maintenance rests with the Planner and Line Supervisor.

If the Planner notes a deficiency that is considered to be an Emergency, he shall immediately notify the area Manager.

If a deficiency is noted to be a TD1 or TD2 priority, it is the Planner's responsibility to ensure the appropriate personnel is aware of the work and of the high priority nature of the work.

A TD1 priority will permit time for formulating a plan of action to correct the deficiency. Planning should begin immediately to ensure corrective action is taken as quickly as possible after the identification of the deficiency.

Regional Managers / Supervisors will ensure corrective maintenance work is complete, in the time frames outlined above, to prevent failure from occurring.

While it is not possible to cover all conditions that a Planner may encounter, the general guidelines found in Appendix A can be used to assist in the classification of defects. In practice, the Planner will assign priority based on his knowledge and experience.

APPENDIX A

GENERAL GUIDELINES FOR CLASSIFICATION OF PRIORITY

ITEM	EMERGENCY	TD1	TD2	TD4
Poles	Broken/severe undermining	Serious cracks or deterioration/unauthorized attachment		Serious checks or splits/woodpecker holes/decay
Crossarms	Broken	Serious cracks or deterioration		Significant rot
Crossbrace			Significant deterioration or broken cross brace	Less significant cracks or deterioration
Cribs				Significant damage or deterioration of the crib timber or loss of rock
Leaning Structures	Line clearance in question or high risk of falling over	Leaning over 2m		Leaning between 0.5m – 1m
Steel Towers		Significant damage/deterioration to support structure or members. Missing or significant deterioration or damage to signs or anti-climbing barrier		Deterioration to support structure or members. Minor deterioration or damage to signs or anti-climbing barriers
Guys / Guy Guards Preform Grips	Broken or disconnected on angle or deadend structure	Buried or severely corroded on angle or deadend structure. Missing guy guard (TD1 or TD2 depending on location, time of year)		Broken, buried, disconnected or severely corroded on other structures. Missing ground attachment. Slack guys.
Anchors / Rod	Rod cut off or undermined on angle/deadend struc.	Rod severely corroded or pulling out on angle/deadend structure		Rod cut or anchor pulling out on other structure types or buried on any structure
Suspension Insulator	50% or more defective in string or cracked/broken rod in composite insulator			Less than 50% defective in string or damage/rod exposed in composite insulator
Pintype / Linepost Insulators	50% or more of the skirts are chipped, cracked or otherwise damaged, or insulator is floating	< 50% of the skirts are chipped, cracked or otherwise damaged Very loose insulator stud		Minor defects – chipped, misaligned Loose insulator stud
Hardware		Missing or Damaged/Worn: High risk of causing interruption	Missing or Damaged/Worn: Moderate risk of causing interruption	Missing or Damaged/Worn: Low risk of causing interruption
Ball Link Eye Bolts			Visible wear in link, >50% worn	Visible wear in link, <50% worn
Conductor Saddle Clamps			FleXall type, extreme wear in clevis bolt	FleXall type, moderate wear in clevis bolt

ITEM	EMERGENCY	TD1	TD2	TD4
Conductor Damage	Sag causing public safety hazard	More than ¼ strands broken		Bird caging. 1 or 2 strands broken
Vibration Dampers				Failed or broken
Overhead Groundwire	Broken and/or severe clearance problem with conductor		Frayed or broken strands	Slack with minor clearance problem
Structure Grounding	Unsupported grounding in danger of contacting conductor	Section missing or cut		Section unsupported-no clearance problem
Group Operated Disconnect Switch	Lock/locking mechanism removed/damaged. Missing or significant deterioration or damage to signs. Missing or significant deterioration to ground connections or ground mats. Blades that are not fully opened or closed. Significant damage to insulators		Moderate damage or deterioration to insulators/handle or other hardware.	Less serious damage or deterioration to infrastructure or signs
In Line Switches	Blades not fully engaged or not fully open. Significant damage to insulators			Less serious damage or deterioration of insulators, blades, hardware or another part of the switch
Corrosion (any component)		Severe cases		
Encroachments	Active operations with clearance concerns (public safety hazard) and/or high risk of causing interruption (Emergency or TD1)		Non-active operations with clearance problem	Other encroachments on r-o-w
Danger Trees		Substantially leaning and high risk of falling and hitting line: TD1 or TD2 depending on situation		Trees within easement that may contact line when felled
High Trees/Brush	Burnt trees close to line and trees that would pose hazard to person climbing tree. Energized trees.			Trees close to line with no evidence of burning and pose no immediate hazard if climbed.

Operating Costs by Breakdown
Test Year Forecasts, Actuals and Variances
2014, 2017, 2020 and 2023

Newfoundland Power Inc.

Operating Costs by Breakdown
Actual vs. Test Year: 2014, 2017, 2020 and 2023
($000s)

		2014			2017			2020			2023		
		Actual	Test Year	Variance	Actual	Test Year	Variance	Actual	Test Year	Variance	Actual	Test Year	Variance
1	Regular and Standby	29,678	30,085	(407)	30,539	31,242	(703)	31,483	31,525	(42)	34,952	33,148	1,804
2	Temporary	2,437	2,433	4	1,836	1,599	237	1,625	2,348	(723)	697	2,108	(1,411)
3	Overtime	3,394	1,965	1,429	3,364	2,908	456	3,425	2,899	526	3,583	3,537	46
4	**Total Labour**	**35,509**	**34,483**	**1,026**	**35,739**	**35,749**	**(10)**	**36,533**	**36,772**	**(239)**	**39,232**	**38,793**	**439**
5													
6	Vehicle Expenses	1,901	1,898	3	1,854	1,586	268	1,725	1,969	(244)	1,940	1,730	210
7	Operating Materials	1,841	1,722	119	1,526	1,674	(148)	1,300	1,567	(267)	1,336	1,287	49
8	Inter-Company Charges	41	50	(9)	26	50	(24)	26	28	(2)	32	28	4
9	Plants, Subs, System Oper & Bldgs	2,312	2,162	150	2,796	2,314	482	3,484	2,970	514	3,672	3,492	180
10	Travel	1,277	1,280	(3)	1,195	1,222	(27)	633	1,156	(523)	1,163	891	272
11	Tools and Clothing Allowance	1,191	1,138	53	1,234	1,155	79	1,156	1,219	(63)	1,738	1,265	473
12	Miscellaneous	1,430	1,317	113	1,361	1,418	(57)	1,633	1,390	243	1,574	1,595	(21)
13	Taxes and Assessments	1,040	1,037	3	1,252	1,173	79	1,116	1,330	(214)	1,308	1,181	127
14	Uncollectible Bills	1,490	915	575	1,386	1,337	49	2,290	1,472	818	1,971	2,208	(237)
15	Insurance	1,243	1,216	27	1,326	1,266	60	1,698	1,408	290	2,425	2,345	80
16	Severance & Other Employee Costs	58	102	(44)	102	74	28	126	76	50	214	133	81
17	Education, Training, Employee Fees	292	403	(111)	329	346	(17)	267	309	(42)	564	354	210
18	Trustee and Directors' Fees	431	408	23	489	476	13	673	519	154	635	712	(77)
19	Other Company Fees	2,222	1,996	226	1,118	2,053	(935)	2,131	2,969	(838)	3,544	2,574	970
20	Stationery & Copying	266	321	(55)	214	285	(71)	246	227	19	307	260	47
21	Equipment Rental/Maintenance	769	746	23	806	819	(13)	656	856	(200)	774	897	(123)
22	Telecommunications	1,710	1,681	29	1,490	1,617	(127)	1,473	1,582	(109)	1,757	1,588	169
23	Postage	1,508	1,512	(4)	1,436	1,584	(148)	1,313	1,332	(19)	1,211	1,202	9
24	Advertising	388	498	(110)	451	465	(14)	460	479	(19)	614	534	80
25	Vegetation Management	1,789	1,935	(146)	2,099	1,863	236	2,306	1,967	339	3,328	2,441	887
26	Computing Equipment & Software	915	822	93	1,451	1,455	(4)	2,199	2,051	148	3,697	3,446	251
27	**Total Other**	**24,114**	**23,159**	**955**	**23,941**	**24,232**	**(291)**	**26,911**	**26,876**	**35**	**33,804**	**30,163**	**3,641**
28													
29	**Gross Operating Cost**	**59,623**	**57,642**	**1,981**	**59,680**	**59,981**	**(301)**	**63,444**	**63,648**	**(204)**	**73,036**	**68,956**	**4,080**